BP Amoco

Upstream
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Group

BP AMOCO UPSTREAM TECHNOLOGY GROUP

Directional Survey Handbook

BPA-D-004

ISSUE 1
SEPTEMBER 1999

Well Integrity Team
HVW – UTG – BPA

Contents

Contents (cont'd)

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Preface

This Issue 1 of the BP Amoco Directional Survey Handbook (BPA-D-004) is applicable in all areas of the BP Amoco organisation.

In addition to the uncontrolled hard copies, this document is also available online via the wellsONLINE and ASK websites, accessible on the BP Amoco Intranet. The online document is to be considered the master version, containing the most up-to-date information.

The distribution of this document is managed by the Upstream Technology Group (UTG) and controlled and administered in Aberdeen by ODL.

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Amendment Summary

Issue No	Date	Description
Issue 1	Sept 1999	First issue of document.

Section 1
Introduction

Contents

Section 1

Introduction

Who this Handbook is for, and what it's about.

The BP Amoco Directional Survey Handbook (BPA-D-004) is the Company's principal reference on directional well planning, anti-collision and survey procedures. It supersedes the BPX Directional Survey Handbook (WEO-X16), the Amoco NSDG Directional Navigation and Survey Procedures (AMO-D-004) and the Amoco Anti-Collision Handbook.

1.1 About this Handbook

Audience

The Handbook provides essential guidance to all those who need to know about well positioning and how BP Amoco manages it. The primary audience is Drilling Engineers, Well Planners and Survey Specialists working in and for BP Amoco.

Margin Icons

- ➔ Reference to another section in the Handbook
- 🗐 Reference to a technical paper or publication
- ! Indicates a BP Amoco Standard Practice

Ownership and Confidentiality

The contents of the Handbook are the property of BP Amoco, but are not considered confidential. The material may be used outside the Company provided BP Amoco's ownership is respected and acknowledged. Users may reproduce parts of the Handbook within the limits usual for copyrighted material.

Additional Copies

The Handbook is a controlled document. Controlled paper copies of the Handbook are available on request from the Wells Document Controller, Well Integrity Team, UTG. Requests for copies outside BP Amoco should be made to the Directional and Survey Specialist, Well Integrity Team, UTG. The Handbook is also available on the BP Amoco Intranet.

Electronic Copies

The Handbook, including copies of the forms in Appendix C, is available on the BP Amoco Intranet from the WellsONLINE page via 'Well Engineering' and 'Directional Drilling'.

Changes and Updates

Suggestions for changes are always welcome and should be addressed to the Directional and Survey Specialist, Well Integrity Team, UTG. It helps the change process if suggestions are made using the Change Request form, a copy of which is in Appendix C. Updates to the manual will be issued to all controlled copy holders as they are made.

Disclaimer

BP Amoco will not be liable for any use made of this Handbook, or the material in it, outside the Company.

1.2 Directional Survey and Value Addition

Much of this Handbook may appear overly complex and prescriptive to readers unfamiliar with recent developments in directional survey management. This section gives the motivation, in terms of value added to the upstream business, of those developments.

Risk Control

Much of the well positioning process is concerned with the avoidance of mistakes. Put another way, it ensures the delivery of objectives which most people involved in the upstream business take for granted.

SURFACE POSITION

The well's surface position must be directly above or at a known horizontal offset from the geological target located by the seismic survey, often taken months or years before.

The entire value of a well, development, or acreage rides on the consistent fulfilment of this requirement. It is by no means straightforward, especially offshore, in the desert, or in countries with antiquated or obscure mapping systems. Many hundreds of wells worldwide are known to have been drilled from the wrong surface location. Many thousands more are no doubt wrongly assumed to be correctly located. No country, or company, is immune from this danger.

SUBSURFACE POSITION

The wellbore must be drilled such that it intersects an often small and distant geological feature.

Since both well and geological target are invisible from the surface, we can never really know whether the one passes through the other. We can only infer it from survey tool measurements and well results. Disappointing well results are usually attributed to incorrect geological or reservoir predictions, rarely to the well being drilled into the wrong part of the reservoir. This implicit confidence in the calculated well position may be mistaken. Forcing geological models to fit incorrect surveys may dramatically reduce the value of several wells, not just one. (Of course, forcing survey data to fit a pre-conceived geological model is equally bad.)

Compounding the problem of incorrect surveys is the use of multiple databases. It is quite possible that in no oil field in the world are the geologists using an identical set of well surveys for their modelling as the directional drillers are for their planning. Where checks have been made between large drilling and subsurface databases, the number of differences – wells missing completely from one or other database or gross differences in survey data – has run into hundreds. Where no such checks have been made, the number and severity of the differences can only be a matter of speculation.

COLLISION AVOIDANCE

The wellbore must not hit any existing wells which lie between it and the target.

Structure plots of mature fields show the three dimensional maze of existing wells, similar in some ways to a minefield. Despite well diameters being generally very small in comparison with the space around them, the Industry regularly witnesses subsurface collisions. This is a strong indication that overall standards of well survey accuracy and reporting, and of collision avoidance management, are not high. The actual arrangement of wells under a platform may be very different to that shown on a structure plot.

Cost Control

Meeting a well's positioning objectives – and demonstrating the fact – is a complex technical exercise. Doing it at minimum cost requires the balancing of several conflicting design pressures. This can be done using specially designed engineering methods, or by guesswork. BP Amoco favour the former approach.

SURVEY PROGRAM COSTS

The most obvious expenditure associated with well positioning is the direct cost of the survey services and the associated rig time. On mobile drilling units, the cost to the operation of acquiring a gyro orientation survey can be several thousand dollars per single shot. The direct cost of MWD services may exceed $100k for a single well. While comprising a relatively small fraction of total well expenditure, the cost of surveying is high enough to justify careful optimisation.

MAXIMISING DRILLING ROOM

A less visible cost implication of well positioning involves the extra directional drilling work necessary to steer the well within restrictive tolerances. The tolerances may be set for collision avoidance, or to ensure the target is hit. Whatever their purpose, their effect will be to increase hole section costs, either through reduced rates of penetration and increased survey frequency or, more dramatically, through correction runs and sidetracks. It is clearly important not to unnecessarily restrict drilling tolerances. Sub-surface staff should be encouraged to recognise this.

Designing to the Limit

In all engineering disciplines, there is a tendency to make some allowance for imperfect knowledge by overly conservative design.

The result is 'over-engineered' bridges, buildings, casing strings or survey programs. There are two problems with this approach:

- It gives a false sense of security. A moderately over-engineered design is no protection against gross errors, for example selecting the wrong survey tool code or applying magnetic declination with the wrong sign
- It is unnecessarily costly. Running a gyro to TD of every well as standard may deliver final surveys of a uniform high quality, but it is an avoidable expense

The alternative is to eliminate waste by designing in a way which takes full advantage of system performance, whether that be the collapse strength of tubulars, or the accuracy of survey tools. Unfortunately:

A waste-free design process leaves no room for incidental errors.

Instruction in waste-free directional survey design, and guidance on eliminating incidental errors, is the dual purpose of this Handbook.

1.3 The Design-Execute Principle

There is a common theme running throughout this Handbook – that the directional survey process is best managed by **designing** the directional program to meet specific objectives, then **executing** the program according to the design. This can be termed the 'design-execute principle'.

Examining any question or decision about well positioning against this principle is almost guaranteed to help in its resolution.

➔ The purpose and content of the Directional Design and Well Survey Files are explained in Sections 6.4 and 6.6

At a high level, all wells share (or should share) a common positioning process. The centrality of the design-execute principle to this process is illustrated in Figure 1.1. Each stage of the process generates part of the documentary trail which demonstrates fulfilment of the well's positioning objectives. These documents may conveniently be retained in two files, one covering the design and one the execution of the positioning operation.

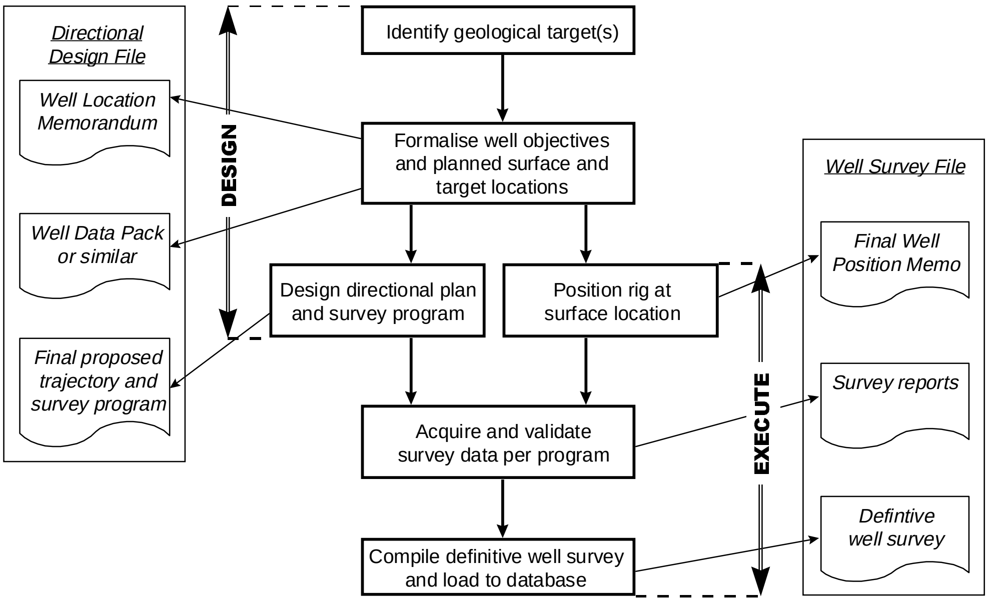


Figure 1.1

Well positioning process and associated files

Section 2
Policy and Standards

Contents

Section

2

Policy and Standards

What BP Amoco Policy says about directional surveying and what it means for your Business Unit.

The vocabulary used to describe the status of instructional documents can be confusing. Terms such as 'policy' and 'guideline' usually carry a specific meaning in BP Amoco and should always be used with care. The following terms are used throughout this Handbook.

A **policy** is an explicit requirement of the BP Amoco Drilling and Well Operations Policy document ('the Drilling Policy'). The status of this document is described below.

The section of the Drilling Policy on Wellbore Trajectory Control is intentionally brief, to encourage a holistic approach to assessing technical integrity. Compliance is generally equated with 'approval by a qualified person appointed by the BP Amoco Senior Drilling Manager'. This qualified person is currently the Directional and Survey Specialist, UTG Well Integrity Team. Approval will be based largely on the fulfilment of certain **policy expectations** described later in this section. These expectations detail the practical implications of the Drilling Policy and should be accorded the same status.

A **recommended practice** is a method or approach considered 'best' by the Technical Authorities in BP Amoco. Deviations from recommended practices should be very rare. They require specific justification and must be thoroughly discussed, recorded and approved, at least to BU Team Leader level. The BU Team Leader should make an objective assessment of his/her competency to assess such deviations and when in doubt should seek advice from the UTG Technical Authority. The BP Amoco Anti-Collision Recommended Practice (➔ 4.3) falls into this category.

The term **BP Amoco standard practice** used in this Handbook refers to a specific convention, specification or procedure which Business Units are requested and expected to follow. While failure to comply with a standard practice may not directly jeopardise technical integrity, it will invariably do so indirectly by causing incompatibility with shared software, databases and service company procedures.

A **guideline** is a suggested method or approach which does not require specific justification for deviation. Instructions in this Handbook which are not accorded one of the above titles are guidelines.

2.1 Drilling and Well Operations Policy

The BP Amoco Drilling and Well Operations Policy (the 'Policy') is a Group policy document issued under the authority of the Technology Vice President (Operations) and the stewardship of the Head of Drilling.

Ultimate operational responsibility for drilling lies with Business Unit Management, so the practical status of the Policy may differ across the Group. Nevertheless, a Business Unit which is not in compliance with the Policy and has not

conducted a formal risk assessment of the implications will be in an exposed position regarding compliance with *Getting HSE Right*.

Copies of the Policy may be obtained from the Document Controller, UTG Well Integrity Team, Aberdeen.

2.2 Policy Expectations

This section gives the well positioning requirements of the Drilling Policy in *italics*. Each requirement is followed by the policy expectations which it implies.

The full list of policy expectations may be considered as the minimum requirements for multi-well developments, where data complexity and anti-collision issues are at a maximum. For isolated exploration and appraisal wells, a slimmed-down set of key requirements will usually be more appropriate. Such a list is given at the end of this section.

1 Directional Database

(12.5) A database of well trajectories (planned and actual) and all project data (slots, targets, locations and projections) shall be maintained in a form approved by a qualified person appointed by BP Amoco Senior Drilling Manager. This safety-critical database shall be the subject of a written plan approved by BP Amoco that describes how it shall be managed throughout the Business Unit life cycle.

1.1 The Directional Data Management Plan will give details of:

- Where the data is stored
- Who has responsibility for maintaining the technical content of the database

- Who has responsibility for physical management of the database
- The arrangements by which each third party involved in managing the data will hand it over to the Business Unit on completion of their contract

1.2 A single database will be identified and maintained as definitive for each development.

1.3 Position reference data, such as vertical datums (usually Mean Sea Level) and survey reference direction (True North or Grid North) must be consistent and well-defined.

1.4 A single trajectory will be identified and maintained as definitive for each drilled well or side-track, including abandoned hole sections.

1.5 Agreement between well position data held on drilling and sub-surface databases will be monitored, and discrepancies will be resolved.

1.6 A comprehensive search for position data relating to nearby wells will be made prior to drilling in a new area. All such data will be stored on the definitive database.

1.7 All wellbore survey data stored on the definitive database will have an associated accuracy model.

2 Surface Positioning

(8.4) The final position of all spud locations shall be confirmed by a qualified surveyor.

(8.8) The rotary table elevation, relative to seabed at mean sea level and water depth (offshore drilling units) or the rotary table elevation relative to ground level (land drilling rigs) shall be determined and formally recorded.

2.1 For single isolated wells, the planned surface well location will be determined under the supervision of a Company Surveyor and recorded on a standard Well Location Memorandum.

2.2 In the case of wells drilled from existing fixed installations, a properly certified survey report of the installation will be produced. It must contain details of the location and orientation of the installation and the locations of the drill slots relative to the installation reference point.

2.3 Well surface positioning procedures used by external contractors will be assessed for technical integrity and compliance with *Getting HSE Right* by a Company Surveyor.

2.4 The final surface well location will be determined by a qualified surveyor, verified by a Company Surveyor, and recorded on a Final Well Position Memo.

2.5 The appropriate geodetic reference data for each well will be determined by a Company Surveyor and stored with the definitive wellbore survey.

2.6 The drilling zero elevation (RTE, KBE etc.) relative to:

- Ground level and the geodetic vertical datum (land wells)
- Seabed and mean sea level (offshore wells) will be measured, formally recorded and communicated to the directional service company

3 Survey Program Design

(12.1) Survey programs for all wellbores shall be designed such that the wellbore is known with sufficient accuracy to:

a) Meet local government regulations

b) Penetrate the geological target(s) set in the well's objectives

c) Minimise the risk of intersection with any nearby wellbore

d) Drill a relief well

(12.2) The performance specification of all instruments employed on operations shall be approved for the use by a qualified person appointed by BP Amoco Senior Drilling Manager.

3.1 The surveying program will be designed to meet clearly stated positioning objectives.

3.2 Only survey tools or services validated for use by a Company Directional Specialist will be included in survey programs.

3.3 The survey program design will take proper account of surface or subsea position uncertainty.

3.4 Well position uncertainty calculations will be made using accuracy models and algorithms validated by a Company Directional Specialist.

3.5 A geometrical positioning tolerance around each target location will be defined based on geological or engineering constraints.

3.6 A reduced Driller's Target will be calculated which makes proper allowance for well position uncertainty.

3.7 It must be demonstrable that the survey program minimises the risk of drilling an unsuccessful relief well. The demonstration will be based on a calculation of well position uncertainty on entering any potentially hydrocarbon bearing zone, and a consideration of:

- The known performance of well ranging tools
- The distance from the previous casing shoe
- The potential for reducing the well's position uncertainty through data re-processing and approach from a suitable direction

3.8 The survey program will provide sufficient data redundancy to validate the performance of each constituent survey. Detailed validation criteria are defined in each tool's Joint Operating and Reporting Procedures (JORPs).

➔ JORPs are discussed in Section 5.10

4 Anti-Collision

(12.6) On multi-well operations a collision check shall be performed on the planned well trajectory

***(12.7) All procedures for assessing tolerable risks of collision, defining minimum well separations and ensuring compliance with such criteria while drilling shall be approved by a qualified person appointed by BP Amoco** Senior Drilling Manager.*

Full policy expectations for anti-collision are given in Section 4.3. For completeness, the requirements of Section 4.3 which are not covered elsewhere in this section are paraphrased here.

4.1 All anti-collision planning work will be completed prior to a section being drilled.

4.2 A clearance scan down the final proposed well trajectory will be performed against the definitive database or a validated copy thereof.

4.3 The minimum allowable separation from each nearby well will be calculated at regular depth intervals.

4.4 Every nearby well detected by the clearance scan will be classified as presenting either a Major or a Minor risk. A nearby well presents a Major risk if a collision with it would carry a significant risk to personnel or the environment. It presents a Minor risk if the risk to personnel and the environment in the event of a collision would be negligible.

4.5 The minimum allowable separation from a Major risk well is:

$3(\sigma_1+\sigma_2) + \frac{1}{2}(d_1+d_2) + S_b + 0.01$ DD (DD < 1000m)

$3(\sigma_1+\sigma_2) + \frac{1}{2}(d_1+d_2) + S_b + 10$m (DD > 1000m)

where

σ_1 = Planned well positional uncertainty at 1 s.d.

σ_2 = Interfering well positional uncertainty at 1 s.d.

d_1 = Hole size in planned well

d_2 = Casing OD in interfering well

S_b = Allowance for survey bias.

DD = Drilled depth.

4.6 The minimum allowable separation for minor risk wells will be calculated from:

$$\sigma\sqrt{2\ln\left(\frac{d_1+d_2}{R\sigma\sqrt{2\pi}}\right)}+\frac{1}{2}\left(d_1+d_2\right)+S_b$$

where:

$\sigma = \sqrt{\sigma_1^2+\sigma_2^2}$

R = Tolerable Collision Risk

4.7 The Tolerable Collision Risk will be derived from a consideration of the likely consequences of collision and the cost of reducing the risk and will be approved by the Business Unit.

4.8 Drilling tolerances will be represented on an anti-collision diagram (a travelling cylinder plot annotated with tolerance lines).

4.9 Each anti-collision diagram will be shipped to the rig prior to the relevant section(s) being drilled.

4.10 After each survey is taken, the as-drilled position of the well will be marked on the anti-collision diagram.

4.11 Wellsite staff do not have permission to cross any tolerance line within the depth interval to which it applies.

4.12 In the event of a tolerance line being crossed inadvertently, or it being impossible to drill ahead without crossing a tolerance line, drilling operations will cease until the situation has been assessed by office-based staff.

2.3 Standard Practices

BP Amoco directional and survey Standard Practices are explained fully in the relevant sections of the Handbook, where they are highlighted with a **!** symbol in the margin. For convenience they also are stated here, with references.

1. All wellbore surveys will be referenced to a recoverable surface or subsea location with known co-ordinates and co-ordinate system identification (the **Well Reference Point**).

2. All wellbore survey data will be corrected to either Grid or True North, and labelled as such (➔ 3.1).

3. Magnetic Declination will be determined either from:
   a) The latest version of the British Geological Survey Global Geomagnetic Model (BGGM, ➔ 3.2), or
   b) Direct measurement of the local field, with or without a time-varying correction (IFR, ➔ 4.8).
4. Travelling cylinders will be plotted with the planned well at the centre and zero relative azimuth (ie. 'north') at 12 o'clock (➔ 4.4).
5. Survey position calculations will be by Minimum Curvature (➔ 4.8).
6. Definitive directional surveys will be compiled using standard rules (➔ 6.6).

Section 3
Theory

Contents

Section 3
Theory

Contents (cont'd)

Section
3

Theory

An introduction to the science of well surveying.

This section includes as much theory as most non-specialists will ever need to know about the surveying of wells. It is not intended as an easy-to-read textbook on the subject, but more as a single source for a collection of useful data, tables, diagrams and other information.

3.1 Surface Positioning

BP Amoco has a group of Land and Hydrographic Surveyors with whom resides the Company's expertise in all aspects of onshore and offshore surface positioning. Technical guidance should be sought in the first instance from the Senior Surveyor, UTG Seismic Quality and Survey Team, Sunbury.

Some Geodetic Theory

GEOID AND ELLIPSOID

The Earth's surface is an irregular shape, undulating several thousand metres from ocean trenches to mountain ranges. Much smoother, but still not geometrically regular, is the equipotential surface corresponding to mean sea level over the oceans. This is known as the **geoid**.

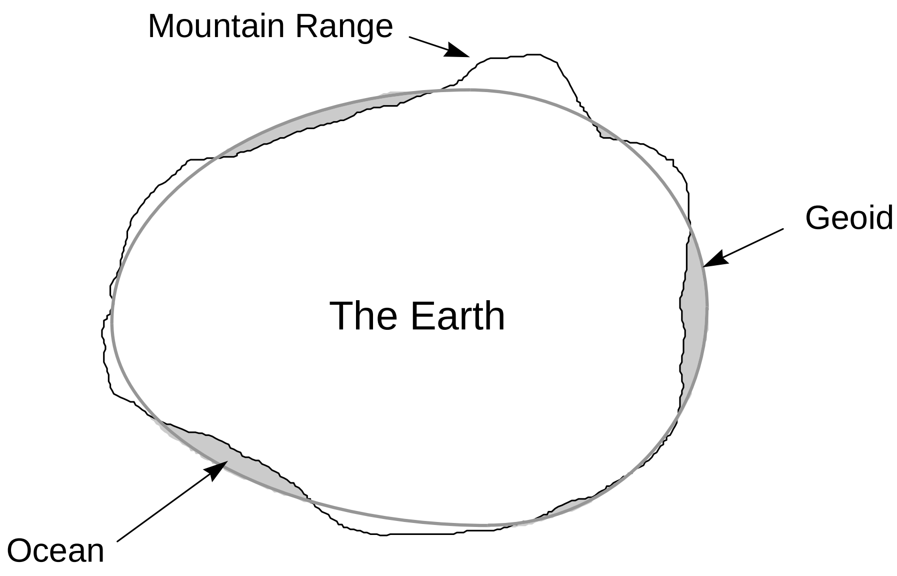


Figure 3.1

The Earth's surface and the geoid

The geoid undulates up to a hundred metres relative to the best geometrical approximation to the Earth's surface – the **ellipsoid**. Geodetic ellipsoids (this term is now preferred to that of 'spheroid') are defined by their size (semi-major axis = 'a') and shape (inverse flattening = '1/f'). To complete the co-ordinate system, the position and orientation of the ellipsoid with respect to the solid earth must also be defined. This is the job of the **geodetic datum**.

There are two types of ellipsoid in common use. Locally fitting ellipsoids are defined to coincide very closely with the geoid over a small part of the Earth's surface. An example is Clarke's 1866 ellipsoid which is used throughout North America. The Clarke 1866 geometrical model is defined to be coincident with the geoid at Meade's Ranch in Kansas, through the NAD27 geodetic datum definition. The same figure has been adopted in certain other areas, for example the Phillipines, but using different geodetic datums.

Globally fitting ellipsoids approximate to the geoid over the whole Earth, but necessarily provide a rather poorer fit. WGS 84 is a geographical co-ordinate system defined by combining a globally fitting ellipsoid (also called WGS 84) with a geocentric datum. It is used by the Global Positioning System (GPS).

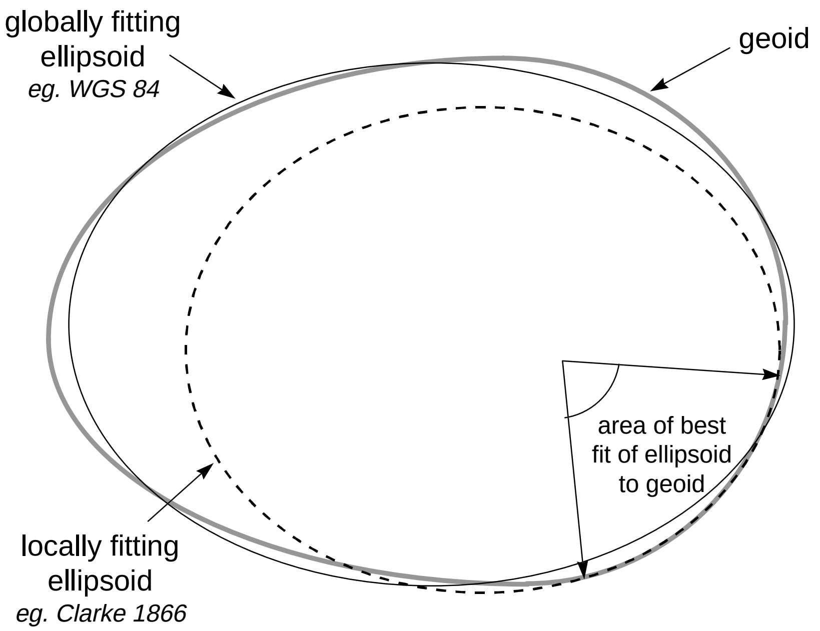


Figure 3.2

Globally and locally fitting ellipsoids

The latitude and longitude of a point on the Earth (its geographical co-ordinates) are defined relative to a particular ellipsoid. If either the ellipsoid or its geodetic datum change, so will the latitude and longitude of the point. Thus latitude and longitude do not define a point uniquely. To be unambiguous, they must always be quoted with the applicable geodetic datum and ellipsoid.

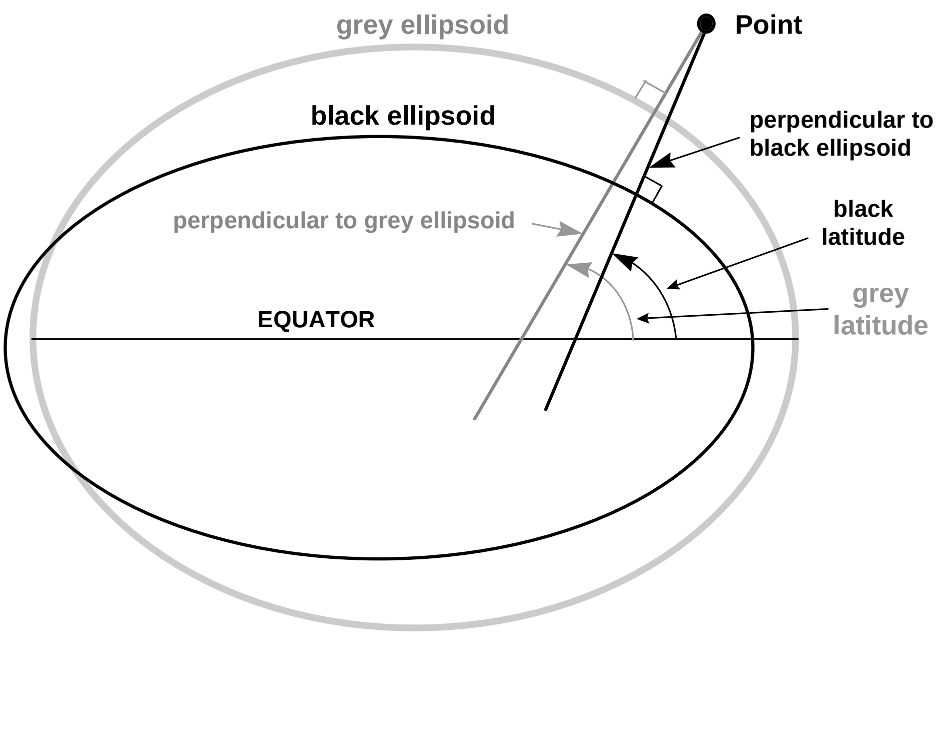


Figure 3.3

Dependence of latitude on choice of ellipsoid and datum

As an example, the following co-ordinates refer to the same location and are both correct:

Lat. 50°40'20.661" N	Lat. 50°40'22.723" N
Long. 1°59'03.213" W	Long. 1°59'08.291" W
OSGB 1936 geodetic datum	WGS 84 geodetic datum
Airy 1830 ellipsoid	WGS 84 ellipsoid

Note that WGS 84 combines an ellipsoid and datum definition.

HEIGHTS AND HEIGHT REFERENCE

The heights of points on the Earth's surface, and the depths of geological structures, are usually measured from **mean sea level (MSL)** (ie. the geoid). These heights and depths are measured along the direction of gravity. They are called **gravity-related heights**.

Onshore, a gravity-related height datum which approximates to the geoid will usually have been established. Height datums have names such as Ordnance Datum, Newlyn (ODN) [used in the UK] or North American Vertical Datum of 1988 (NAVD88) [used in the USA].

In marine areas, nautical charts show minimum water depths expected at any state of the tide. These depths are referred to as hydrographic datums such as Lowest Astronomic Tide (LAT) or Mean Low Water Springs (MLWS). Elevations on offshore structures are sometimes referenced to a hydrographic datum such as LAT because this simplifies the air-gap calculations. These hydrographic datums take into consideration the local tidal range. Because tidal range changes with seabed topography, these hydrographic datums are complex surfaces which are only approximately parallel to the geoid. Use of these hydrographic datums should be avoided in well positioning. Rig elevations should be referenced to Mean Sea Level (the geoid) with appropriate corrections being applied. Consult a Company Hydrographic Surveyor.

Heights above the ellipsoid have no physical significance and are rarely used. The big exception is GPS receivers which measure three-dimensional position, including height above the WGS 84 ellipsoid. In order to obtain gravity-related heights from GPS measurements, a value for the geoid-ellipsoid separation (sometimes called "geoid height") must first be subtracted. Geoid height comes from a **geoid model**. Many GPS receivers contain a geoid model and can apply a correction to give mean sea level height. However, many geoid models exist and the model in the GPS receiver may not be the appropriate one to use. Consult a Company Surveyor.

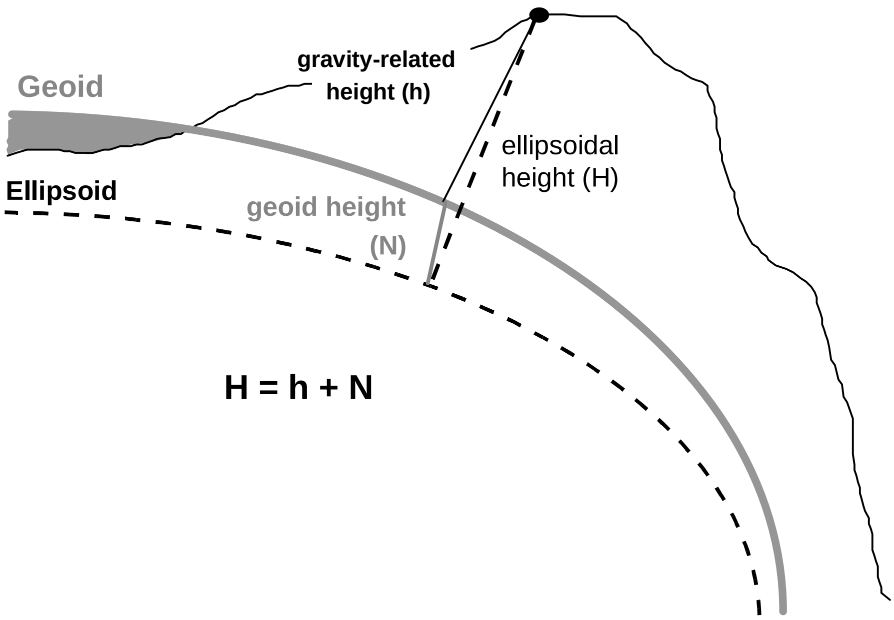


Figure 3.4

Relationship between geodetic heights

The Mapping Grid

Although forming a two-dimensional (horizontal) co-ordinate system, geographical co-ordinates (latitude and longitude) are based on a lattice on the surface of a three-dimensional ellipsoid. Before the advent of digital computers this was inconvenient to work on. To represent the Earth's surface on a flat page or map requires a mathematical transformation from (ellipsoidal) geographic co-ordinates to plane rectangular map grid co-ordinates. These transformations are called **projections**, and the resulting co-ordinates are referenced to a

projected co-ordinate system. We use the term **mapping grid** for permanent, public domain projected co-ordinate systems to distinguish them from temporary **drilling grids** which apply only to individual wells or structures. Projected co-ordinate system names include both the geodetic datum from which the projection was applied and the projection name, for example *ED50 / UTM zone 31N* (in the North Sea) or *Nord Sahara 1959 / UTM zone 31N* in Algeria. Note that map grid co-ordinates remain ambiguous if the projection name (eg. UTM zone 31) alone is given – the geodetic datum must also be identified.

As the ellipsoid is a non-conformable surface, it cannot be transformed without distortion. There are many projection methods, each having specific distortion characteristics. The projection methods most commonly utilised for oil industry applications are Transverse Mercator and Lambert Conic Conformal, which both preserve the shapes of small areas. Other characteristics such as distance and direction suffer from distortion.

All projected co-ordinate systems contain distortion. Generally, the projection method and parameters will have been chosen to minimise distortion over a given geographical area. Beyond this area, distortion becomes unacceptably large. To continue plane rectangular mapping requires the introduction of a new projection and projected co-ordinate system. Frequently a series of **grid zones** are used to map large areas. A commonly encountered grid zone system is the Universal Transverse Mercator or UTM system introduced by the US Army Map Service for western military mapping. The UTM grid system is a series of projections, 60 in each hemisphere spaced every 6 degrees of longitude. These all use the Transverse Mercator projection method (but with differing parameters) and are applied to local geographic co-ordinate systems. Similar zoned systems exist in Germany, Russia and other countries.

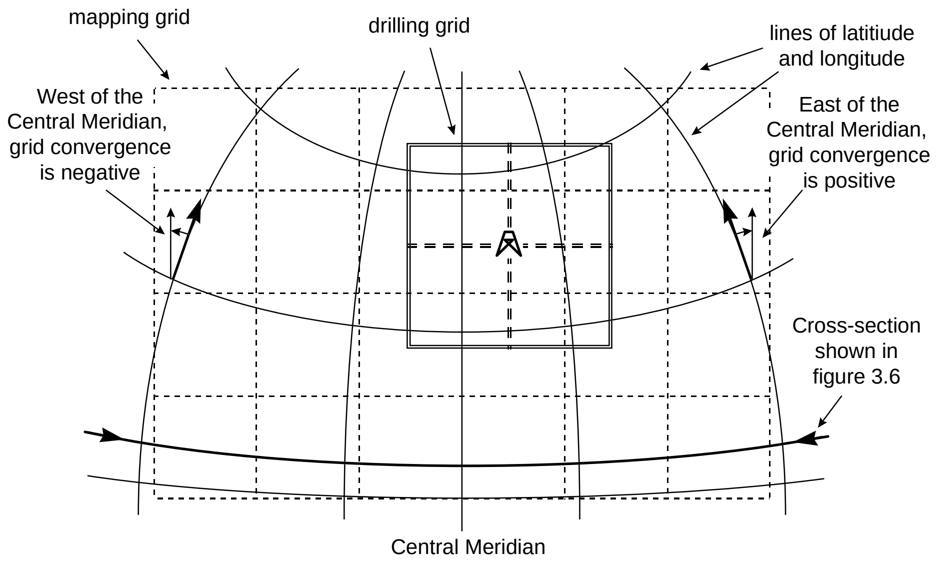


Figure 3.5

Geographical, mapping grid and drilling grid co-ordinates

True North is the direction to the North Pole. It is therefore parallel to lines of equal longitude (meridians) and perpendicular to lines of equal latitude (parallels). North-seeking gyroscopic and inertial survey tools measure the azimuth of the well relative to true north.

Grid North defines the orientation of the mapping grid used in the area. It is therefore parallel to lines of equal east co-ordinate and perpendicular to lines of equal north co-ordinate. Grid north is a mathematical construct and cannot be measured directly by any tool. The angle from true north to grid north is called the **(grid) convergence**. It is positive clockwise, so that convergence is positive (negative) when grid north is east (west) of true north. Typical values are between -3° to +3°. Convergence takes different values in different places, with a variation of 0.01° per km being typical.

If a second map grid is introduced, the grid north direction (convergence value) at a particular point will generally differ from the first map grid. Therefore,

When survey measurements are related to grid north it is essential that the relevant map grid (projected co-ordinate system, including geodetic datum) is identified.

The local distortion in a projection is indicated by the grid convergence and by **(grid) scale factor** which is the ratio of a length calculated from grid co-ordinates to the same length measured on the ground. Typical values of scale factor are between 0.999 to 1.001. It does vary from place to place in a non-linear fashion, typically changing by about 4 parts per million per kilometre.

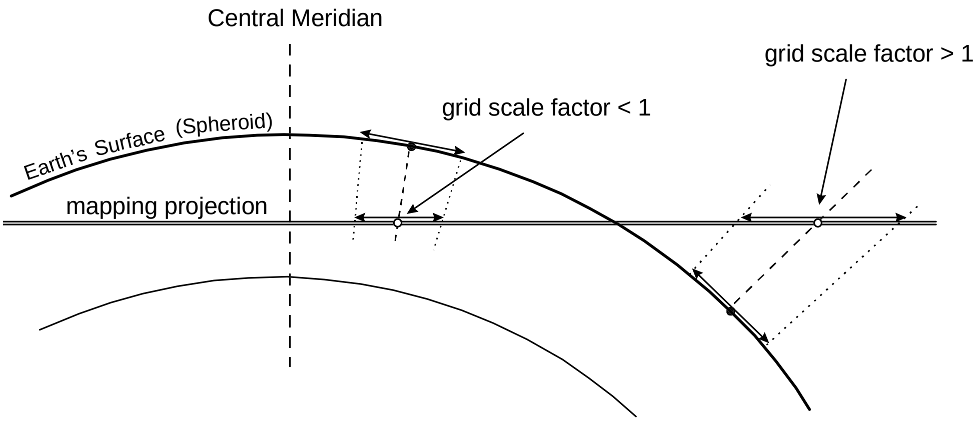


Figure 3.6

Variation of grid scale factor across a mapping grid

The Drilling Grid

During the planning and drilling of a directional well, horizontal co-ordinates are usually referenced to a simple rectangular grid called the **drilling grid**. This is defined by two parameters, for each of which there are two choices:

! BP Amoco Standard Practice

- The **survey reference direction** (= **drilling grid north**) defines the alignment of the north axis of the drilling grid. It is a BP Amoco Standard Practice that the survey reference direction is always either true north or grid north at the drilling grid origin. Where grid north is used, the projected co-ordinate system must be identified

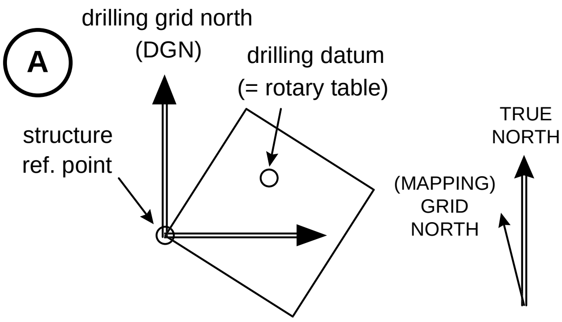
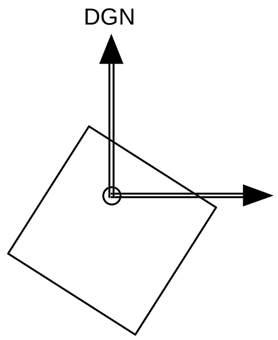
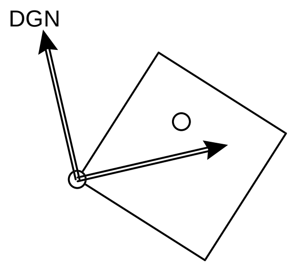
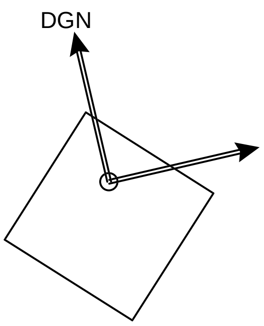
! BP Amoco Standard Practice

- The drilling grid origin defines the position of the drilling grid. It is a BP Amoco Standard Practice that the drilling grid origin is always either the structure reference point (**structure centred referencing**) or the rotary table (**well centred referencing**)

As a consequence of these standards, there are only four possible definitions of the drilling grid within BP Amoco. As the following table shows, all four are in use in different parts of the Company.

Table 3.1

Definition of the drilling grid in some BP Amoco operating areas

A		Structure Centred Referencing Survey Reference = True North *Norway* *UK - Forties* *UK - Magnus* *UK - former Amoco*
B		Well Centred Referencing Survey Reference = True North *USA - Alaska*
C		Structure Centred Referencing Survey Reference = Grid North *UK - former BP* *(excluding Forties, Magnus)* *Netherlands*
D		Well Centred Referencing Survey Reference = Grid North *USA - Gulf Coast* *USA - Land* *Colombia*

DRILLING GRID RECOMMENDATIONS

The wide variety of Drilling Grid definitions used in BP Amoco is a historical legacy and a reflection of there being no definition which is clearly superior on technical grounds. For new developments, the following conventions are recommended:

Survey Reference Direction

- True North in Alaska and Norway
- Grid North in the rest of the world

Drilling Grid Origin

- Well centred referencing in the Americas
- Structure centred referencing in the rest of the world

The Global Positioning System

The Global Positioning System, GPS, is used for nearly all offshore rig positioning and for marking of onshore well locations. In regions of dense forest conventional methods (theodolite and electronic distance measuring) might be used in conjunction with GPS.

GPS is a system of 27 satellites orbiting 20,000km above the earth in a constellation designed to ensure that at least four satellites are visible at all points on the earth at all times. A minimum of four simultaneously visible satellites are required to determine the position of a GPS receiver. Normally more than four, and sometimes up to ten satellites are visible. This improves the accuracy and reliability of the measured position fix. At any location the number of GPS satellites visible changes constantly.

GPS was designed and established as a military navigation system and for reasons of US security GPS satellite signals are intentionally degraded by a process known as selective availability. This decreases the accuracy of positions measured

using GPS to approximately ±100m (±300 ft). Selective availability degradations change with both time and location.

DIFFERENTIAL GPS (DGPS)

Differential GPS is a technology commonly used within the oil industry to improve on the standard GPS accuracy. Errors in the GPS signals are determined by deploying a GPS receiver at an accurately known ‘reference’ station. The assumption is made that these errors will be constant within an area close to the reference station (up to several hundred kilometres). They can be then be broadcast to and eliminated from mobile GPS receivers. The GPS errors measured at the reference station are telemetered to mobile GPS receivers every few seconds.

There are many different DGPS techniques in use. Some employ multiple reference stations, some use satellite communications. DGPS position accuracy is in the range ±1-5 metres and depends primarily on the distance to the reference station, the number of reference stations used, the number of satellites visible and the geometry of the satellites relative to the GPS receiver.

OTHER GPS TECHNIQUES

Several other techniques utilising the GPS signals and advanced surveying equipment and procedures can achieve positioning to sub-metre and even sub-centimetre accuracy. These techniques are utilised in the oil industry, but are not normally required for well surface positioning.

There is a special GPS technique known as **real time kinematic**, or **RTK GPS**. This is similar in principle to DGPS but uses special properties of the satellite signals to achieve position accuracies of ±2-5cm (±1-2 in). Special GPS receivers and high speed telemetry links are required for RTK and the distance from the reference station is limited to 10-20km maximum.

There is also a Russian satellite system known as **Glonass**, similar in operation to GPS. It is less reliable but more accurate than GPS with selective availability applied and provides a useful augmentation to it. Some equipment manufacturers supply combined GPS/Glonass receivers.

A predecessor to GPS is a satellite system known as **Transit**. This system required an observation period of several days and is now rarely used in the oil industry. The surface accuracy of a well positioned by Transit is typically ±10-30 metres.

ELEVATION MEASUREMENT

GPS is a three dimensional positioning system and elevation is derived in addition to horizontal co-ordinates. For positioning offshore, the GPS-determined elevation is used primarily as a check on the proper functioning of system, since antenna height above sea level can be measured directly with a tape. Onshore, GPS-determined elevation is an important co-ordinate. Its accuracy is approximately half that of horizontal co-ordinates (±2-10m for DGPS). GPS height is above the WGS 84 ellipsoid and must be corrected to a gravity-related height datum. Specialist survey advice is required for this.

Other Surface Positioning Systems

Surface positioning within the oil industry is dominated by GPS in its many forms. Before GPS (c. 1990) a variety of radio-positioning systems were used for offshore positioning. Some of these are still in use today. These systems use radio beacons located at known points to measure ranges (or range differences) to a mobile radio receiver. Short range systems such as **Trisponder** and **Miniranger** use microwaves. Longer range systems like **Syledis** and **Maxiran** use 400MHz signals. There are also very long range systems, such as **Pulse/8**. Although GPS has superseded many of these systems they may occasionally be encountered, especially as a backup to GPS

when positioning is critical. They will also appear as the positioning system used to define the location of older wells.

Dynamically positioned vessels will usually use a combination of GPS and acoustics for positioning but will also often use a mechanical system known as a **taut-wire** system. This measures the angle from vertical beneath the vessel of a wire which is anchored to the seabed. When in the vicinity of fixed seabed structures, **laser ranging** may also be used to measure position relative to the structure. Jack-Up rigs located alongside fixed seabed jackets may use mechanical devices to measure distance to the jacket. These devices can be as primitive as graduated aluminium ladders.

Onshore, where vegetation is dense, well locations may be marked using theodolite and electronic distance measuring devices. Usually these **conventional surveys** are tied to GPS control points and the final position of the rig will be confirmed using GPS.

Underwater Positioning

Underwater positioning is usually undertaken using acoustic measurement techniques. Ranges between acoustic beacons are determined by measuring the time it takes a pulse of sound to travel between the beacons. The speed of sound propagation in water needs to be accurately known to convert time into distance and is often the largest source of error in acoustic measurements. This is particularly true when measuring through a column of water, such as from sea surface to seabed, where acoustic propagation speed is likely to vary considerably as a function of depth. There are two different acoustic positioning methods commonly used in support of drilling operations; long baseline (LBL) and ultra-short baseline (USBL) acoustics.

LONG BASELINE ACOUSTICS (LBL)

The LBL method usually involves deploying an array of acoustic transponders on the seabed and determining their positions by making range measurements between pairs of transponders and between the transponders and a surface vessel, typically positioned using DGPS. Some of the transponders may be placed on known features such as existing wellheads or production facilities.

When sufficient data has been obtained to co-ordinate the transponder array, it can be used to position a mobile acoustic beacon by measuring ranges between the beacon and the transponders in the array. The acoustic beacon can be located on an ROV, a temporary guidebase, or any other feature which is to be positioned, such as the drill string. Generally, ranges to at least three transponders need to be measured to position the acoustic beacon. If the depth of the beacon is not being independently determined then four acoustic ranges are required.

Accuracy of acoustic range measurements depends directly upon the accuracy of acoustic propagation speed and is also a function of acoustic frequency. Extra high frequency systems can achieve range accuracies of about ±0.05m (2 in), but have a maximum range significantly less than 500m. Low frequency systems can measure ranges of up to 10km in ideal conditions but with an accuracy of ±2-5m. Other transponders are available between these extremes. Derived position accuracy relative to the transponder array for a static acoustic beacon is typically about the same accuracy as an individual range measurement. If the beacon is moving, or if it is at a significantly different depth to the transponders, then its accuracy may be significantly degraded. Accuracy of the transponder positions will depend upon DGPS accuracy, water depth and velocity profile accuracy.

ULTRA-SHORT BASELINE ACOUSTICS (USBL)

The USBL method determines the three-dimensional position of an acoustic beacon relative to a single acoustic transducer. The transducer is usually fixed to the hull of a surface vessel but can be deployed on any vessel. Range is measured in a similar manner to an LBL system but the three-dimensional direction of arrival of the acoustic signal is also measured at the transducer enabling the beacon position to be determined.

This technique is highly dependent on the three dimensional attitude (heading, pitch and roll) of the transducer being accurately known at the time of measurement. USBL measurements are usually made through the water column, so they are particularly susceptible to errors in the acoustic velocity profile. The method does not need any seabed acoustic transponders and is a relatively easy system to use.

The uncertainty in USBL acoustic position has two components. The distance component is largely a function of the water velocity uncertainty. The angle component is largely a function of heave/pitch/role sensor accuracy and calibration and can vary significantly. The accuracy of a USBL position depends greatly on the geometry of the transducer and the point. If the transducer is vertically above the point there will be minimal error – less than 0.5% of water depth. If the geometry is such that the USBL ray path is very oblique, the USBL error may be several per cent of water depth. Seek guidance from a Hydrographic Surveyor in the UTG Seismic Quality and Survey Team.

Another acoustic system known as **short baseline**, or SBL, is similar to USBL except that three or more transducers are installed on the vessel.

CALIBRATION

All acoustic systems need to be properly calibrated prior to operational use. LBL calibration entails co-ordinating the array of acoustic transponders. USBL (and SBL) calibration consists primarily of determining errors in the attitude measurements of heading, pitch and roll. Accurate measurement of the acoustic propagation velocity (speed of sound in water) is necessary for all acoustic positioning systems.

Wellhead Position Uncertainty

➔ Section 3.3 explains the statistical concepts behind position uncertainty

Most surface positions are determined either directly or indirectly using GPS. DGPS used directly has an accuracy of 1-5m (2 standard deviations). This is the horizontal position accuracy of the GPS receiver antenna. There will be a small additional error in measuring the horizontal offset between the GPS antenna and the centre of the rotary table if the antenna is not mounted on the drilling derrick. Such offset errors are caused by uncertainties in the rig or platform orientation and the measured offset distances. More important is the serious potential error source of a blunder in the application of the offset direction.

The accuracies of positions derived from radio-positioning systems vary tremendously, depending upon resolution of the system, its calibration, geometric deployment etc. Older well surface locations positioned by these systems will typically have absolute accuracies of ±5-100 metres, generally ±20-50 metres. The relative accuracy of two wells positioned using the same system will usually be better than this.

➔ Section 4.2 gives the surveying requirements for relief well contingency

For deep water wells, the largest contributor to wellhead position uncertainty is often the unknown lateral offset between sea level and mudline. The size of this uncertainty will greatly affect the ability to drill a subsequent relief well. It is possible to measure the offset using acoustic techniques.

Wellhead position accuracies differ from their downhole equivalents in two important respects:

- The distinction between relative and absolute accuracies is more important, since both sorts of measurement are possible. The relative positions of objects in one structure are often determined much more accurately than the position of the structure in space

- More use is made of repeat measurements to help randomise errors. The accuracy of a single or instantaneous position fix will not be as good as for a position determined from a series of measurements recorded over a period of time

There is no equivalent of approved survey tool error models for surface and underwater positioning systems. Accuracy is strongly dependent on the equipment, the quality of its installation and calibration, and the procedures and techniques employed during operations. These can vary significantly. Actual performance is often significantly worse than that claimed by the system vendor. For expert advice on surface position accuracies, contact the UTG Seismic Quality and Survey Team.

3.2 The Earth's Magnetic Field

The Earth's magnetic field at a point is defined by a vector, often written **B**. It is specified by the

- **Declination**, D or δ, defined as the angle clockwise from true north to the horizontal projection of the magnetic field vector, or put another way, as the true bearing of **magnetic north**

- **Dip angle**, I or Θ, defined as the vertical angle from the horizontal to the magnetic field vector, measured positive downwards
- **Field intensity**, F or B, which defines the strength of the field

The magnetic field vector is sometimes described by its components in the true north, true east and vertical directions. These are conventionally called X, Y and Z.

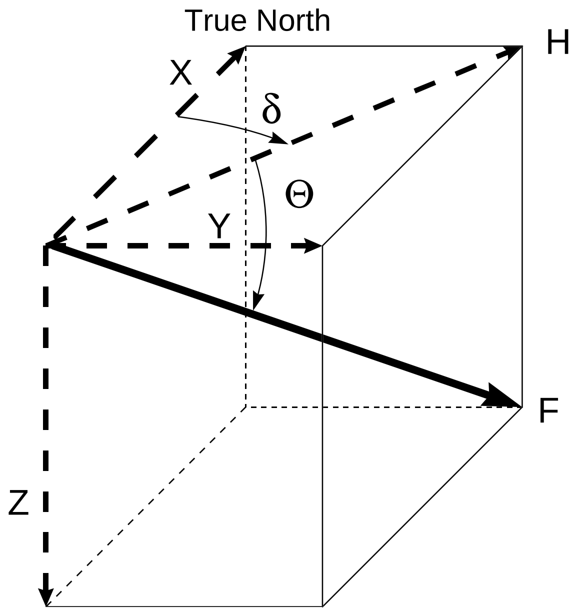


Figure 3.7

Components of the magnetic field vector

The SI unit of magnetic flux density is the Tesla. Since the Earth's magnetic field is relatively weak, the unit most commonly used to measure it is the **nano-Tesla (nT)** = 10^{-9} Tesla.

The following table gives approximate values for the magnetic field in some of BP Amoco's major operating areas. The list is in decreasing order of horizontal field intensity, which corresponds to increasing difficulty of magnetic surveying.

Location	Lat.	Long.	Declination	Dip Angle	Field Intensity	Horizontal Intensity
Vietnam	8°N	109°E	0°	0°	41,000 nT	41,000 nT
Abu Dhabi	24°N	54°E	1°E	36°	43,000 nT	34,000 nT
Egypt	28°N	33°E	3°E	41°	42,000 nT	32,000 nT
Kuwait	29°N	48°E	3°E	44°	44,000 nT	32,000 nT
Algeria	29°N	1°E	2°W	39°	40,000 nT	31,000 nT
Trinidad	10°N	61°W	14°W	34°	34,000 nT	28,000 nT
Colombia	5°N	73°W	6°W	31°	33,000 nT	28,000 nT
Azerbaijan	40°N	50°E	5°E	58°	49,000 nT	26,000 nT
USA – Gulf Coast	28°N	88°W	0°	59°	48,000 nT	25,000 nT
Bolivia	17°S	62°W	9°W	-11°	24,000 nT	23,000 nT
Argentina – Austral	54°S	66°W	12°E	-50°	32,000 nT	21,000 nT
UK – Wytch Farm	50°N	2°W	4°W	65°	48,000 nT	20,000 nT
UK – Central N. Sea	57°N	1°E	4°W	71°	50,000 nT	17,000 nT
Canada – Alberta	55°N	114°W	20°E	77°	59,000 nT	13,000 nT
Norwegian Sea	65°N	7°E	2°W	75°	52,000 nT	13,000 nT
USA – Alaska	70°N	147°W	29°E	81°	57,000 nT	9,000 nT

Table 3.2

The magnetic field in some of BP Amoco's operating areas (approximate values as of 1 July 1999)

The Geomagnetic Field

Near the Earth's surface, the magnetic field vector may be expressed as the sum of three separate components:

THE MAIN FIELD

The main field is generated in the Earth's core and accounts for approximately 98% of the field strength at the Earth's surface. Both its strength and direction vary relatively slowly with time. In the North Sea, the rate of change is typically some tens of nano-Teslas per year in intensity and up to a tenth of a degree per year in direction.

THE CRUSTAL FIELD

The crustal field is due to local rocks. For practical purposes it may be regarded as unchanging. Localised variations in the crustal field are known as **crustal anomalies**. They are typically some tens of kilometers across, with intensities of a few hundred nano-Tesla.

THE DISTURBANCE FIELD

The disturbance field is due to electrical currents flowing in the upper atmosphere and magnetosphere, and currents induced in the sea and in the ground. It fluctuates on timescales of minutes to hours. During severe magnetic storms, the intensity of the disturbance field may vary by a few thousand nano-Tesla at North Sea latitudes, and it can take any direction, leading to variations of several degrees in magnetic declination.

The effect of magnetic disturbances on survey services can be managed by a system of alerts (➔ 5.2) or effectively eliminating using in-field referencing (➔ 4.8).

Geomagnetic Models

Being smooth, and fairly static, the main field can be accurately represented by a **geomagnetic main field model**. This is a set of a few hundred numbers calculated from numerous observations by spherical harmonic analysis – a sort of three-dimensional curve fitting. It is a BP Amoco Standard Practice to use the British Geological Survey Global Geomagnetic Model (**BGGM**) for making estimates of the local magnetic field, unless actual observations are available. The BGGM is re-calculated annually by the BGS from thousands of individual observations. Some companies use an alternative model called the IGRF (International Geomagnetic Reference Field), but this is updated only every 5 years, and does not meet the accuracy standards assumed in BP Amoco's approved survey error models.

! BP Amoco Standard Practice

3.3 Position Uncertainty

All anti-collision and target analyses rely on our ability to make reliable estimates of well position uncertainty. The results of these analyses can be communicated without referring to the well position uncertainty directly, but on occasion it may be useful to do this.

The surveyed position of any point in a well may be in error in three directions (north, east and vertical), so position uncertainty is really a three-dimensional quantity. However, we are usually only interested in one or two dimensions simultaneously. For example,

- When steering a horizontal well in a thin bed, only the vertical position of the well is of immediate importance. This is a one-dimensional problem
- When attempting to drill through a polygonal (ie. flat) target, only the position of the well perpendicular to the direction of drilling is of immediate importance. This is a two-dimensional problem

Problems of position uncertainty involving one, two and three dimensions are best treated completely separately.

Uncertainty in One Dimension
First, two definitions:

The **standard deviation** (symbol s.d. or σ, sigma) of a random variable is defined as the square root of the average squared difference between the variable and its mean. The standard deviation of the number of spots obtained with a single throw of a die is 1.71. Note that standard deviation is not defined in terms of a 68% confidence level – that is a special case for the normal distribution.

If a random variable takes values between X and Y on average P times in every hundred, then [X,Y] is called a **P% confidence interval**. As an example, [5'3",6'5"] might be a 95% confidence interval for adult males in the US. It is common practice to use a fixed number of standard deviations from the mean as a measure of confidence. The intervals [-σ,+σ] and [-2σ,+2σ] are shown in figure 3.8. These are sometimes called the 1 sigma and 2 sigma (or 1-sd and 2-sd) confidence intervals. The precise confidence level represented by these two intervals depends on the distribution. In the case of a symmetrical triangular distribution, the confidence levels are 65.0% and 96.6%.

THE ONE DIMENSIONAL NORMAL DISTRIBUTION

For good mathematical reasons, the normal or Gaussian distribution is most often chosen to model position errors. The normal distribution with mean μ and variance σ^2 (and therefore standard deviation σ) has the probability density function:

$$f(x) \quad = \quad \frac{1}{\sigma\sqrt{2\pi}} \exp\left\{\frac{-(x-\mu)^2}{2\sigma^2}\right\}$$

The following figure shows the 1 sigma and 2 sigma confidence intervals for the standard normal distribution. These represent 68.3% and 95.4% confidence respectively (which is true for a normal distribution with any mean and variance).

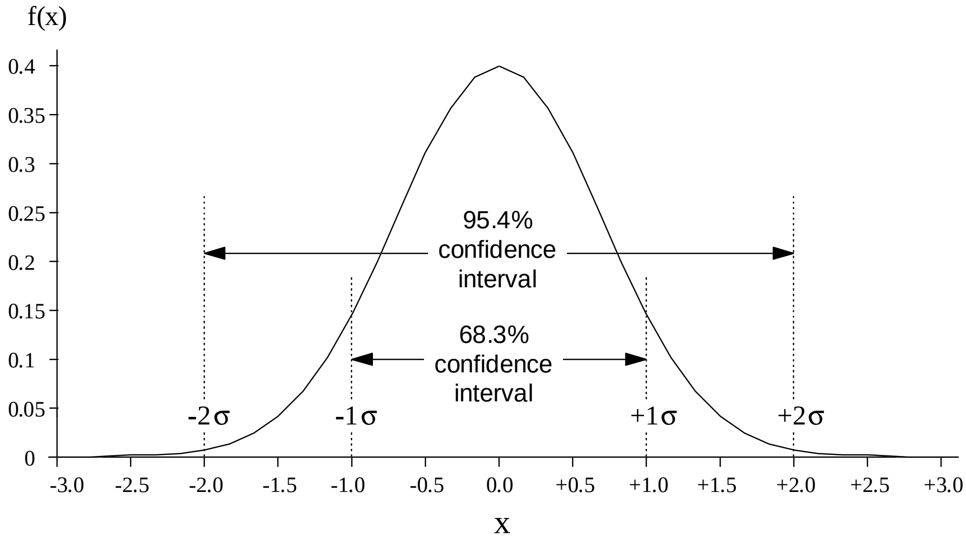


Figure 3.8

The one dimensional normal distribution

Because 95% is the level of confidence most widely used by statisticians, position uncertainties are most commonly quoted at the 2 sigma level. The use of 3 sigma uncertainty levels is also widespread, but the extra confidence gained (4%) is rarely with the extra cost (c. 50%) of meeting the tighter tolerance. It must be remembered however, that the implicit equation '+/-2 sigma = 95% confidence' includes the assumption that the random quantity is distributed approximately normally. Other confidence intervals of the one-dimensional normal distribution are:

confidence level	standard deviations	confidence level	standard deviations	confidence level	standard deviations
25%	± 0.32	80%	± 1.28	95%	± 1.96
50%	± 0.68	85%	± 1.44	98%	± 2.33
75%	± 1.15	90%	± 1.65	99%	± 2.58

Table 3.3

Confidence intervals for the one dimensional normal distribution

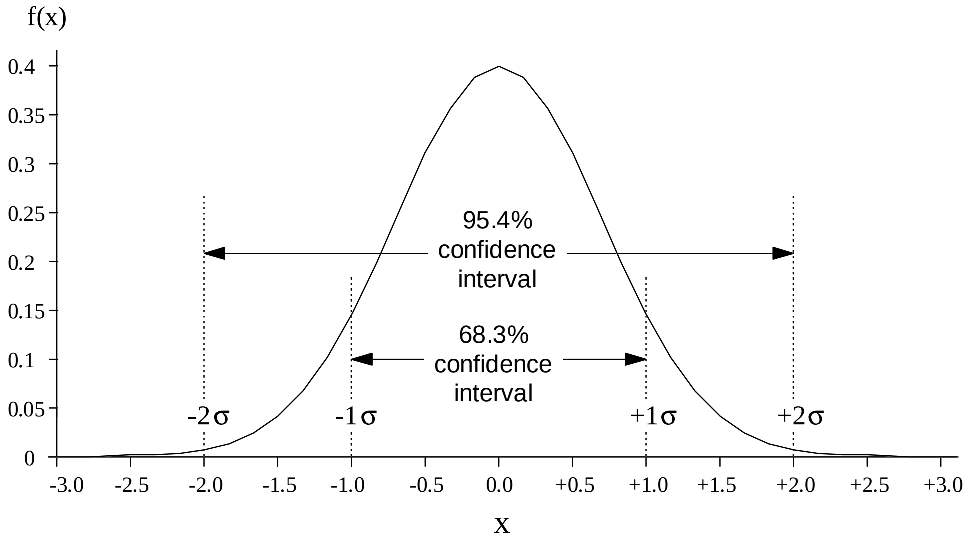


Figure 3.8

The one dimensional normal distribution

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75%	± 1.15	90%	± 1.65	99%	± 2.58

Table 3.3

Confidence intervals for the one dimensional normal distribution

Uncertainty in Two Dimensions

Figure 3.9 represents the positions of a well in the horizontal plane at a given depth, each position corresponding to a different survey with the same instrument. By considering the distribution of points in one dimension at a time, it is possible to draw a histogram of the distribution along any direction. In the figure, this has been done for the North and East directions.

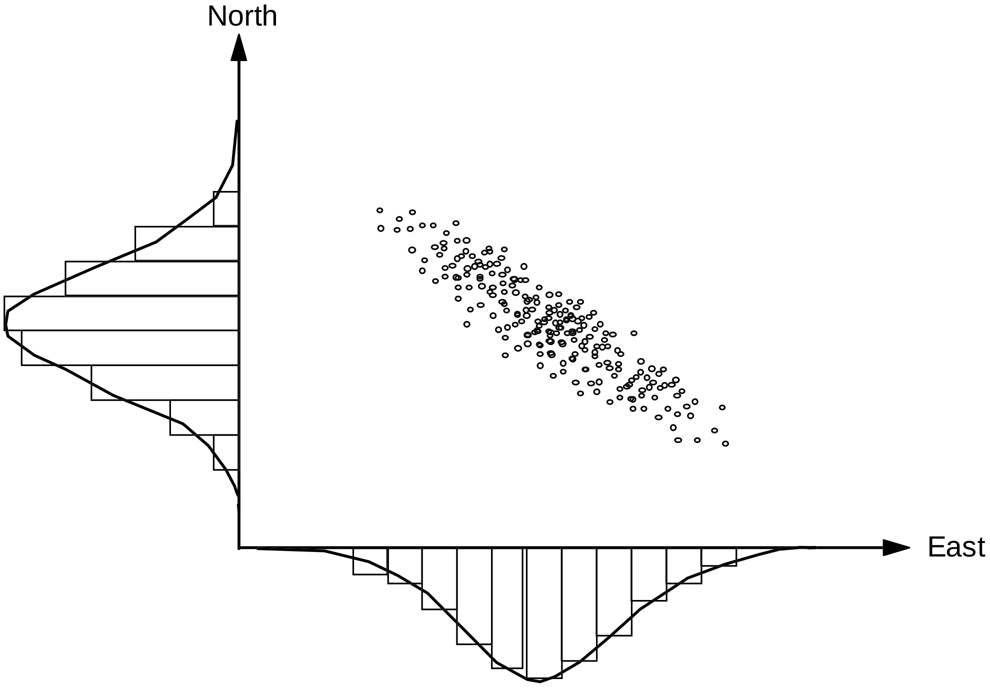


Figure 3.9

A two dimensional distribution resolved in two directions

Clearly, there will be directions in which the spread of the points is a maximum and a minimum. It turns out that these two directions are always perpendicular. The ellipse with semi-axes parallel to these two directions and equal in length to the standard deviations of the distribution along them is called the **standard error ellipse** (or 1-sigma error ellipse) of the distribution. This is shown in the following figure.

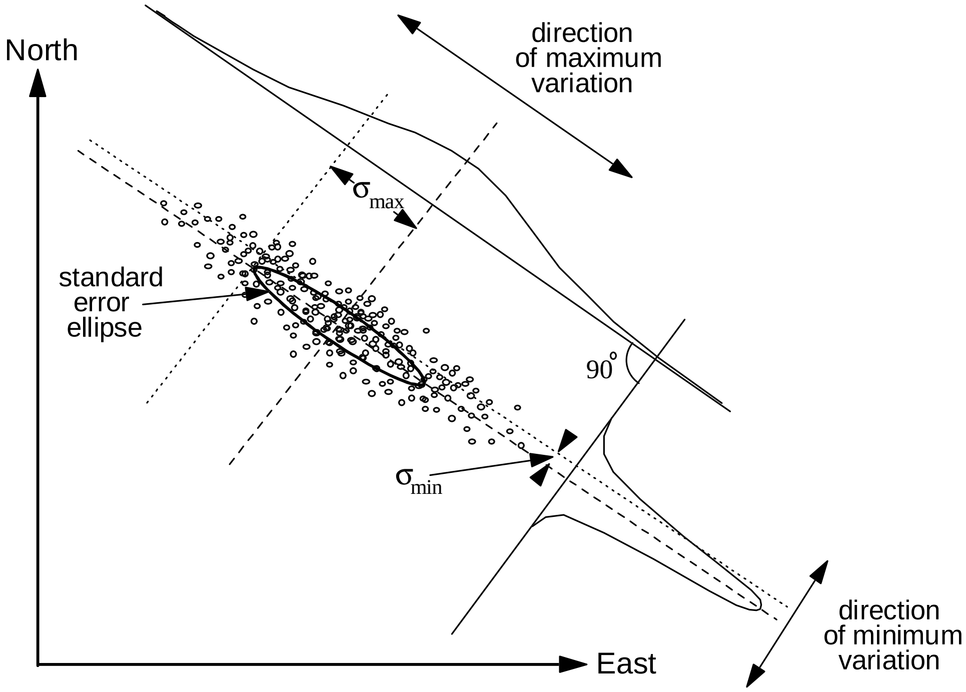


Figure 3.10

Principal directions and the standard error ellipse

➔ Section A.2 includes more details on the mathematics of position uncertainty, including how to calculate other values for Table 3.4.

In the same way that an interval in one dimension has an associated confidence level, so an area of the plane in two dimensions also has an associated confidence level. For the special case of the two dimensional normal distribution, we can be more specific. For this distribution, confidence regions of minimum area for a given level of confidence are multiples of the standard error ellipse. For example, the 2.45 sigma error ellipse, which has semi-axes equal to $2.45\sigma_{max}$ and $2.45\sigma_{min}$, is the 95% confidence region of minimum area. Other values are:

confidence level	standard deviations	confidence level	standard deviations	confidence level	standard deviations
25%	0.76	75%	1.67	95%	2.45
39.3%	1.00	86.5%	2.00	98.9%	3.00
50%	1.18	90%	2.15	99%	3.03

Table 3.4

Confidence intervals for the two dimensional normal distribution

3.4 Position Uncertainty Calculations

This section deals only with the well bore position uncertainty relative to the wellhead. In some applications, including relief well contingency (➔ 4.2) the surface and water column uncertainty is of equal or even greater importance. These must be combined with the downhole uncertainty to give an estimate of the absolute position uncertainty of the welbore in space.

For a full description of the method, see **SPE 56702 Accuracy Prediction for Directional MWD**

A comprehensive description of the mathematics behind survey position uncertainty calculation is beyond the scope of this Handbook. However, it is useful to give an outline of the principles involved.

Assumptions

The universality of the method relies on several simplifying assumptions:

- Errors in calculated well position are caused by measurement errors at wellbore survey stations
- Survey stations are simultaneous measurements of along-hole depth, inclination and azimuth
- Errors from different error sources are statistically independent
- There is a linear relationship between the size of each measurement error and the corresponding change in calculated well position
- The combined effect on calculated well position of several measurement errors at several stations is equal to the sum of their individual effects

Definitions

An **error source** is a physical phenomenon which contributes to tool measurement error. An **error term** describes the effect of an error source on a particular survey tool measurement. It is defined by the following data:

- A name, eg. 'crustal declination error'
- A weighting function, describing the effect of the error source on the tool measurement
- A mean value (zero, except for bias errors)
- A magnitude (to be quoted at one standard deviation)
- Coefficients ρ1, ρ2 and ρ3 describing the error correlation between stations in the same survey, surveys in the same well, and surveys in the same field respectively

The three correlation coefficients and the mean value determine the error term's **mode of propagation** – how it's effects accumulate down the well. There are five types:

Propagation Mode	ρ1	ρ2	ρ3	mean
Random	0	0	0	0
Systematic	1	0	0	0
Per-Well	1	1	0	0
Global	1	1	1	0
Bias	1	1	1	≠0

Table 3.5

Error term propagation modes

An **error model** is a set of error terms chosen with the aim of properly accounting for all the significant error sources which affect a survey tool.

➔ Appendix B contains a list of the current BP Amoco approved error models.

Calculation Process

Calculation of survey position uncertainty requires the following data:

- A surface location – some error terms are sensitive to geographical latitude or the magnetic field
- A well trajectory, ie. a list of measured or planned survey stations
- A breakdown of the trajectory into depth ranges, and the error model applicable in each range
- Details of each error model

➔ Section A.2 describes the interpretation and manipulation of position covariance matrices.

Vector errors (at 1 s.d.) are computed for each error term at each survey station. These are then summed statistically according to their mode of propagation. The final result is the position uncertainty of each survey station, represented by a 3×3 matrix, called a **covariance matrix**.

Survey Bias

Most survey measurement errors are equally likely to be positive or negative, with a most likely value of zero. A well containing only this type of survey error will have a most likely position coincident with its surveyed position. Some authorities treat all errors like this.

Physical reality is, unfortunately, more complex. A few survey errors are asymmetric about zero, being more likely to be positive than negative, or vice-versa. Examples are induced axial magnetic interference (which tends to put survey azimuths north of true azimuths) and drill pipe stretch error (which tends to make measured depths less than true along-hole depths). These errors may be thought of as split into two components, (a) a symmetrical term, representing the uncertain part of the error, and treated in the same way as other symmetric terms (b) a constant term, called a bias, representing the fixed part of the error.

The effect of bias errors is to shift the most likely well position away from the surveyed well position. Their presence is indicated by the following effects:

- Error ellipses are not centred on the plotted well path
- Driller's targets are not centred within the geological target boundary
- On the travelling cylinder plot, no-go areas are not centred on the plotted interfering well path

Along Hole Depth Errors

There are two ways to represent the position uncertainty of a point in a well:

- **Uncertainty at a survey station** describes the uncertainty in the position of the point in space at which the survey tool came to rest. It contains an along-hole component corresponding to the tool's depth measurement error
- **Uncertainty at an assigned depth** describes the uncertainty at the point in the well at the along-hole depth recorded by the survey tool (and assigned to the survey station). It has no along-hole component corresponding directly to the tool's depth measurement error
- The results differ only in the along-hole depth component which, fortunately, is of little importance in most applications

Section 4
Methods

Contents

Section 4
Methods

Contents (cont'd)

Section 4
Methods

Contents (cont'd)

Section

4

Methods

Mathematical, logical and procedural tools for optimum well positioning.

This section is about applying the theory described in the previous section to the real engineering problems of well positioning. Most of the associated mathematics, included for the benefit of specialists and software developers, has been collected in Appendix A.

Policy or Guideline ?

This section is a mixture of policies, recommended practices, guidelines and technical notes. Section 2 of the Handbook explains these terms, and specifies exactly what constitutes compliance with BP Amoco Drilling Policy.

4.1 Multi-Well Development Planning

Motivation

Although the bulk of this Handbook is concerned with the positioning of individual wells, the Drilling Engineer for a multi-well development must also ensure that the near-surface part of each well is optimally placed with respect to all the others, including those not yet drilled. Enabling all slots on the installation to be utilised effectively requires planning. The inevitable consequence of poor planning is empty slots from which wells cannot be safely drilled. The associated costs of new facilities or of lost reservoir development opportunities may be huge.

The trend towards drilling more high angle and multi-target wells, often draining smaller reservoirs, has tended to reduce the number of slots in each installation. While this should tend to ease near-surface congestion, it also means that there is less flexibility to change slot allocations part-way through the development. Pressure to reduce top-side costs has also led to a reluctance to provide spare slots. The importance of thorough planning is therefore as great as ever.

Contents and Maintenance of the Plan

Each field development requires a comprehensive Plan which incorporates:

- Existing facilities, including drilled wells
- Geological target locations
- The allocation of drilling slots to targets
- Directional well plans from all slots, including those to which no target has been assigned
- A drilling and tie-back sequence, with periods of simultaneous operations identified as necessary

The Plan will usually best be represented graphically by:

- A slot bay diagram, showing the position and assigned target, well type and drilling sequence for each slot
- A small-scale plot showing the entire field
- A large-scale plot showing the near-surface well trajectories

The directional plans need not be optimised at this stage, but must be within the known limits of directional control. All plans must also have been checked for anti-collision issues. Plans from unallocated slots need only be extended until they are clear of the main well cluster, but they should be included

in all anti-collision analyses. This will prevent early wells from closing off all possible drilling corridors from empty slots.

Each version of the Plan is only ever a snap-shot of the field at one point in its development. The continual flow of new information and new technology will never allow one Plan to remain fixed for long. However,

the inevitable need for frequent revisions is not a valid argument against maintaining a detailed Field Development Plan.

There are practical limits to how much optimisation work it is sensible to carry out as part of each revision, and how comprehensive each review of the Plan needs to be.

Guidelines for Successful Planning

The key to successful field development planning is maintaining the maximum possible flexibility.

Figure 4.1 is a plan view (or 'spider plot') of a carefully planned multi-well development.

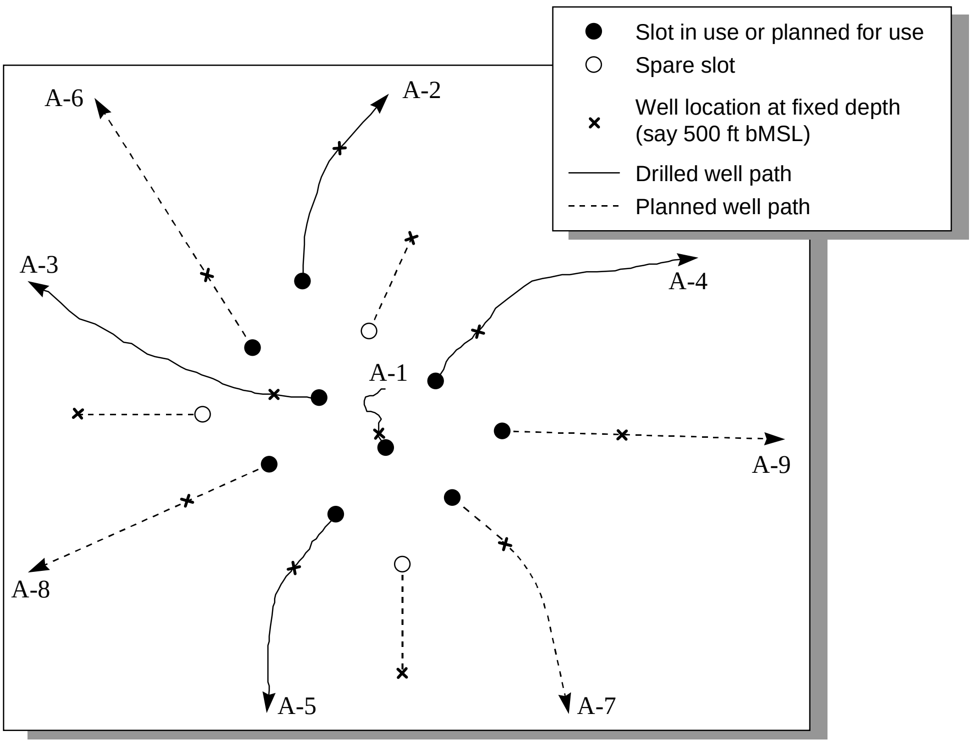


Figure 4.1

A well planned development

This development exhibits the following characteristics:

- Central slots have been drilled first. Where possible, corner slots are kept as 'spares', or are planned for use late in the development. This helps avoid the need ever to drill from slots which are hemmed in by existing wells
- Wells have been planned from all slots, including spare slots which are not currently planned for use
- Spare slots are evenly distributed around the slot bay. This gives maximum flexibility in the events of additional targets being identified
- Near-surface nudges take each well path directly away from the cluster, achieving maximum separation at as shallow a depth as possible
- Northerly slots are used for northerly targets, easterly slots for easterly targets and so on. This minimises the need for wells to pass over and under one another
- Nearby targets are drilled from central slots, distant targets are drilled from outer slots. Again, this helps separate the wellbores at the maximum rate
- Consecutive wells are not drilled from adjacent slots. This may enable simultaneous drilling and tie-back operations to be carried out

Additional factors which may be relevant when planning the slot/target allocation, drilling order and top-hole trajectories include:

- Conductor setting depths and/or kick-off depths may need to be staggered (ie. alternating deep and shallow along each row of slots) in order to minimise formation damage at a particular depth
- The known or predicted directional behaviour of kick-off drilling assemblies, directional conductor shoes, or wells drilled from deviated conductors

- The location and lay-out of top-side facilities
- Gas production or injection wells may be best drilled from outer slots in order to minimise the modelled blast intensity following a loss of containment

By way of contrast, figure 4.2 shows a poorly planned multi-well development, where the good practices listed above have not been followed.

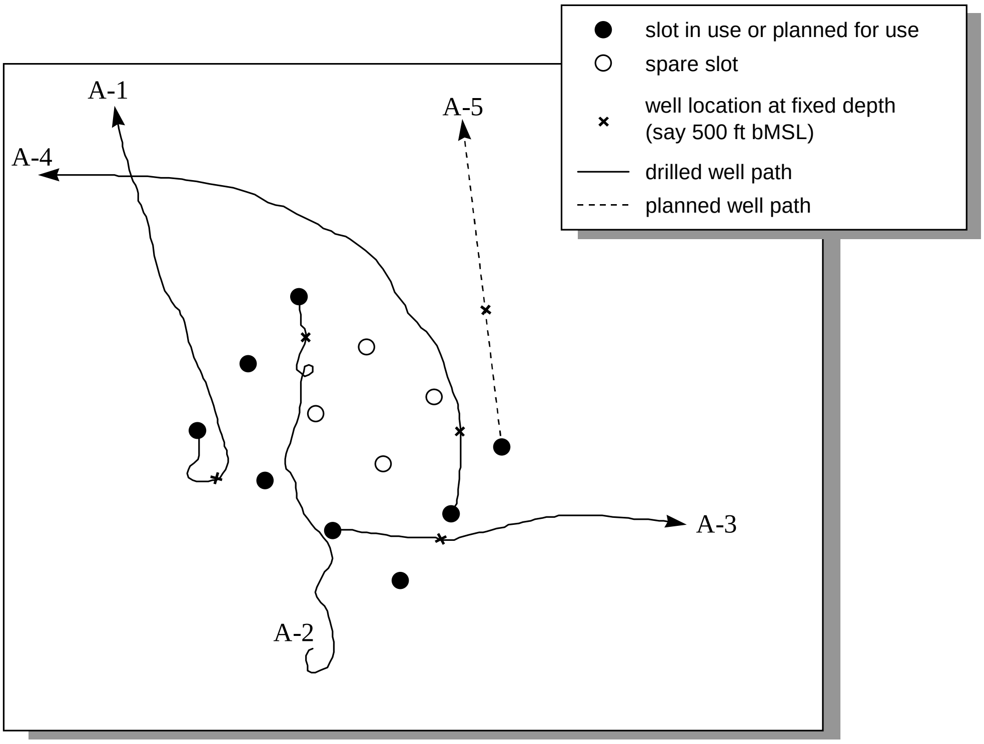


Figure 4.2
A poorly planned development

The engineer is planning only one well ahead, making each one as easy as possible to drill without regard to the consequences for future wells. As a result, the possible drilling corridors from empty slots are rapidly becoming closed off. With less than half the slots used, it may already be too late to recover fully from this situation.

Discipline in Following the Plan

Once a Plan is developed which enables wells to be safely drilled from all slots, it is essential that Drilling Engineers, Well Planners and Directional Drillers maintain the discipline needed to follow it.

It may be necessary to incur extra cost to avoid the paths of wells that have yet to be drilled, or to survey the top-hole sections of wells more accurately than would be needed were the well being drilled in isolation.

Any other approach would be false economy.

4.2 Survey Program Design

What is a survey program ?

The Survey Program for a well is the planned sequence of survey data to be acquired during and after the drilling operation. A fit-for-purpose survey program will:

- Guarantee sufficient data to determine the well position with the accuracy necessary to meet the well's positioning objectives
- Provide sufficient redundancy to enable each acquired survey dataset to be independently checked and validated
- Achieve the above requirements at minimum cost/risk to the operation

➔ Appendix C contains a Survey Program Data Sheet, useful for inclusion in the drilling program

The survey program is a part of the well design and **must be included as a separate and distinct part of the drilling program**. As such, it acts as a set of instructions to the rig team. These instructions must be detailed enough to ensure that the design assumptions remain valid. In particular, the survey program should contain:

1. Tool types.
2. Start and end depths, with criteria for success.
3. Running configuration (centralised in casing, pump-down etc).
4. Corrections or data processing to be applied.
5. Survey station intervals.
6. Special running procedures, if any.
7. Contingency for tool failure.

It should be stated in the program that standard BP Amoco operating and reporting procedures (JORPs) are mandatory except where specifically stated within the program.

➔ JORPs are covered in Section 5.10

The Design Process

The process for constructing a survey program can be summarised as 'define objectives, select surveys, check objectives will be met'. Figure 4.3 illustrates with more detail.

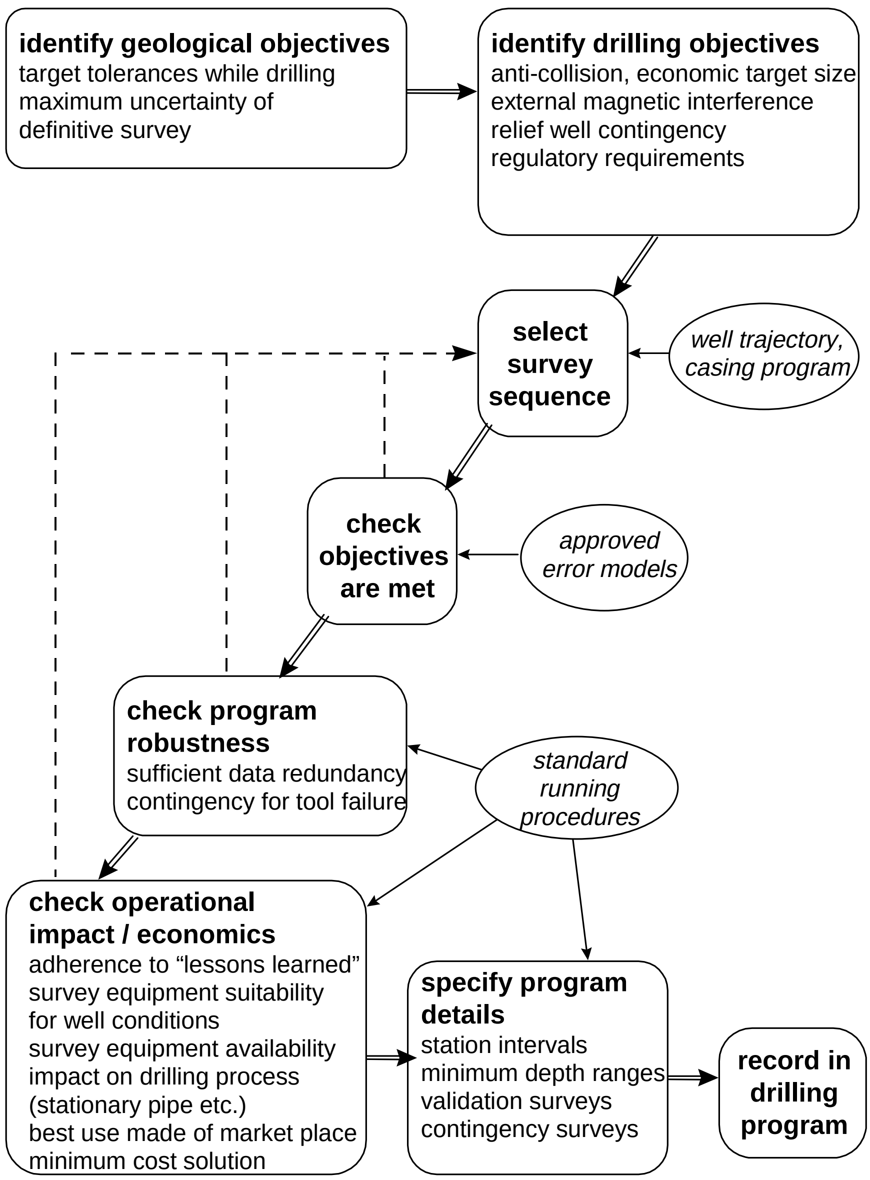


Figure 4.3

Flowchart for survey program design

Clarity in the geological and drilling **positioning objectives** of the well is the key to successful survey program design. The two most complex sets of objectives are managed by anti-collision planning and target analysis, discussed later in this section. Additional objectives and issues to be managed are discussed here.

Relief Well Contingency

Drilling a relief well in the event of a blowout requires locating the target well accurately enough virtually to intersect it. This is always difficult. It can be made all but impossible if the target well is poorly surveyed.

The following guidelines are applicable to all wells for which there is the possibility of intersecting a hydrocarbon bearing zone. For isolated exploration and appraisal wells, several factors conspire to mean that the feasibility of subsequent intersection by a relief well will often dominate the survey program design:

- Increased blow-out risk due to uncertainty over formation fluids and pore pressures
- Relatively large wellhead position uncertainty, particularly in deep water
- Absence of other demanding survey objectives, such as small targets or anti-collision constraints

DRILLING AND POSITIONING A RELIEF WELL

No two relief wells are the same, but certain steps in the drilling and positioning process are likely to be common to most:

1. The surface location of the target well will be determined as accurately as possible. A land well can be re-surveyed, but not-so an offshore well, which may be undetectable somewhere in a huge blowout crater. In this case, reliance will have to be placed on the original surface positioning data. It can be assumed that the relief rig will be positioned relative to the best estimate of the target well surface location without appreciable uncertainty. It is often good practice to utilise the same surface positioning systems and methods for the relief well as were used for the target well.

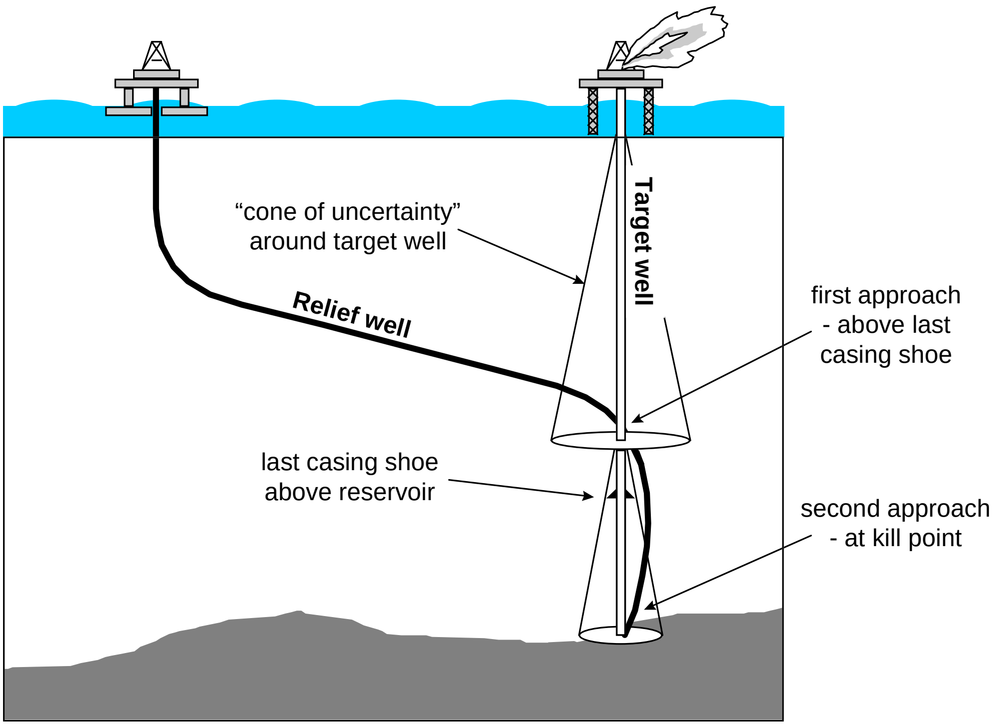
2. All the surface positioning and directional survey data from the target well will be re-examined by experts. They will re-check and re-process the data in an attempt to detect and correct for any systematic errors and minimise the uncertainty around the newly computed position. Their success will depend entirely on the quality of the data left behind by the well surveyors.

3. The relief well will not be aimed directly at the open hole 'kill-point' – the chances of passing close enough to perform a successful kill would be several hundred to one against. Instead, it would most likely be planned to pass close to the target well some distance above the last casing shoe, where well-to-well ranging tools – which work by inducing and detecting a magnetic field in the target well – would have most chance of success. The maximum range of these tools is dependent on formation anisotropy and conductivity, mud type, and a number of other factors, but they can generally be expected to detect a casing string at least 100ft (30m) distant.

4. The relative position of the relief and target wells having been accurately determined by the first approach, the survey uncertainty is now effectively re-set to zero. The survey data in both wells will be further examined in an attempt to determine the exact position of the kill point. Several errors normally contributing to the build-up of survey uncertainty may be eliminated at this point.

Figure 4.4

Schematic of a relief well



5. The relief well will be aimed at the newly determined kill point position. If there is drill pipe in the target well, it may be possible to home-in on the well using well-to-well ranging. If communication between the wells is not established, or if it is inadequate to perform the kill operation, the relief well will have to be side-tracked, possibly several times, until success is achieved.

WELL POSITIONING REQUIREMENTS

The following will maximise the chances of success of any subsequent relief well positioning operation. The positioning systems for all wells should be checked against the requirements listed below. Where they are not met, the Wells Team should conduct a risk assessment and be able to fully justify non-compliance. This is particularly important for deep water exploration wells.

1. For each hole section which may penetrate an abnormally pressured hydrocarbon bearing zone, position the previous casing shoe to an absolute uncertainty of no greater than 30m (100ft) at 2 standard deviations. This may be determined from:

$$2\sigma \textit{ Absolute Uncertainty} = \sqrt{\left[(2\sigma \textit{ surface uncertainty})^2 + (2\sigma \textit{ surface-to-seabed uncertainty})^2 + (2\sigma \textit{ lateral wellbore uncertainty})^2 \right]}$$

Example: Offshore well in 800m of water.

2σ surface uncertainty	= 5m	(typical of DGPS)
2σ surface-to-seabed unc.	= 8m*	
2σ lateral wellbore unc.	= 10m	
2σ Absolute Uncertainty	$= \sqrt{[5^2 + 8^2 + 10^2]} = 13.7$m	

* See Section 3.1 for a discussion of USBL acoustic position uncertainty.

Land and hydrographic surveyors will usually quote uncertainties at 2 standard deviations (2σ) by default. Check. In some high step-out development wells, the above criterion may not be practically achievable. A dispensation may be justified on several grounds:

- Knowledge and/or depletion of the reservoir makes a blowout very unlikely
- Wellbore uncertainty is substantially less in the high-side direction that in the lateral direction (this fact could be used by careful planning of the relief well)
- The type of survey data to be acquired is amenable to further processing and accuracy improvement, should it be necessary. IIFR is an example
- There is no practical means of improving the accuracy of the survey program

2. In any hole section which may penetrate an abnormally pressured hydrocarbon bearing zone, ensure that good quality digital survey data is acquired <u>before</u> such zones are encountered. This typically means either using MWD in the hole section, or running an electronic magnetic multishot or dipmeter log part-way through the section.

   Camera-based magnetic surveys are not adequate for this purpose, except over short depth intervals (c. 300m or 1000ft).

3. For offshore wells drilled from floating vessels, the surface to seabed horizontal offset must be determined simultaneously with a surface position fix. The measurement must fulfil the accuracy requirement (1). It is sufficient to demonstrate that the horizontal drift of the well in the water column cannot be so large that the accuracy requirement is exceeded.

➔ LBL acoustics are described in Section 3.1

   There are a number of ways in which limits on the departure from verticality may be determined. Measuring the well inclination in the water column, probably with MWD, is among the simplest. Use of LBL acoustics is probably the most accurate (but also the most expensive).

External Magnetic Interference

Magnetic survey tools navigate relative to the magnetic field at the directional sensors. In general, this field has three components:

1. The geomagnetic field. This is the field which the tool is designed to detect. Special techniques such as in-field referencing (➔ 4.7) have been developed to make accurate estimates of it.

2. Drill string interference field. Due to steel in the drill string itself, the strength of this field is minimised by ensuring the directional sensors are surrounded by non-magnetic components in the drill string (➔ 4.9).

3. External interference field. Due to casing or fish in the drilling well or in nearby wells. It is generally not possible to avoid these fields completely, or to correct for their effects. They must be managed by ensuring that no magnetic azimuth is relied upon which may have been influenced by an external field.

DRILLING OUT OF CASING SHOE

Because it acts like a bar magnet, the magnetic field immediately below a casing string is far stronger, and acts at a far greater distance, than the field adjacent to the string's length. Experience shows that the magnetic azimuths may be unreliable up to 60m (200ft) from a casing shoe. Generally speaking, it is better to discard all such surveys from the final dataset. An exception to this occurs where a sharp build (or drop) is commenced immediately below a casing shoe. Discarding the inclination data in the surveys below the shoe may have a significant and important effect on the computed well TVD. In such cases, it is advisable to retain the survey stations, interpolating azimuth data if necessary.

DRILLING OUT OF A CLUSTER OR CASING WINDOW

The distance to which adjacent casing strings have a significant effect on magnetic azimuths is a matter of some debate. In general, the engineer should <u>expect</u> interference within 30ft (9m) of another string, and should be <u>prepared</u> for it within 50ft (15m).

For planning purposes, survey programs should contain gyroscopic single shots over the interval of possible interference. An exception may be made when drilling vertical hole near surface, provided that:

- There is sufficient initial well separation (typically 30ft, but see below)
- The inclination of the well is continuously monitored

- Drilling ceases and gyro tools are mobilised should the inclination exceed a pre-set threshold. This threshold should be based on the standard minimum separation criteria for anti-collision

MAGNETIC INTERFERENCE SCANS

The extent of the likely depth interval over which external magnetic interference is likely can be estimated from an examination of a clearance scan listing, or better, by an automatic magnetic interference scan – a utility offered by some software. The aim of this scan is to estimate the likely combined magnetic interference due to several neighbouring wells. There is always considerable uncertainty in the estimate caused by the variables on installation type and permanent magnetisation of casing strings. The calculation performed by the software is as follows:

1. Perform a travelling cylinder scan of all existing wells (1,…N) against the planned well as reference. Planned wells are excluded from the set of offset wells.
2. At regular depths, d_i, down the planned well, record the perpendicular separation from all the offset wells, $S_1(d_i)$, $S_2(d_i)$,…$S_N(d_i)$.
3. At each depth, d_i, calculate the **equivalent distance** of a single casing string:

$$S_{equiv}(d_i) = \left(\frac{1}{S_1(d_i)^2} + \frac{1}{S_2(d_i)^2} + \ldots + \frac{1}{S_N(d_i)^2} \right)^{-\frac{1}{2}}$$

   This formula is based on the simplistic but useful assumptions that (a) the interfering field from each casing string is equal in intensity (b) the intensity decreases with the square of the distance from the casing.

4. Plot or tabulate equivalent distance against depth down the planned well.

DRILLING ROUND A FISH

The likelihood of magnetic interference when drilling round a fish can be determined using a magnetic interference scan (or a simple clearance scan, since only one offset well is involved). The need for gyroscopic surveys will depend on whether the separation from the fish can be guaranteed and monitored using inclination and highside toolface measurements alone.

Position Uncertainty of the Definitive Survey

There are two types of geological positioning tolerance:

- How close the well must be drilled to its planned location
- The accuracy to which the final position of the well must be determined

The first of these is covered under Target Analysis (➔ 4.5). The second, which is an altogether different question, may be of considerable importance for reservoir modelling, equity determination, or some other reason. Nevertheless, it is rare that a Geologist will volunteer this information without being prompted. The drilling engineer or survey management specialist should take care to ask this question, as part of establishing a complete list of survey objectives for the well.

Regulatory Requirements for Surveying

The requirements for wellbore surveying laid down by governments or other regulatory bodies are usually qualitative rather than quantitative, and focus on the minimisation of safety and environmental risks. Almost without exception, adherence to the recommendations in this Handbook will be more than sufficient to satisfy official requirements. Nevertheless, when operating in a new or unfamiliar area, engineers should check if there are any specific requirements for well positioning operations or reporting, both surface and sub-surface.

Data Redundancy

The assumption that a carefully constructed survey programme will meet all the specified survey objectives is invalid if errors significantly larger than those predicted by the validated error model are present in the surveys. This applies to both survey instrument errors and gross error or blunders. The specific purpose of the quality control procedures in the JORPs is to prevent such errors going undetected, but in isolation these can never be totally effective.

The most powerful method of quality control available to the engineer is comparison of results from different tools. In particular, results from all tools must be consistent, within the limits of the approved error model, with those from similar and different types of tool run in the well. It is thus a rule of survey program design that:

➔ The precise interpretation of this rule for MWD surveys is described in Section 5.2

the amount of corroborative data in the form of check shots, multiple probe runs and the like must be sufficient at every stage to confirm the performance of each instrument run in the hole.

4.3 Anti-Collision – Recommended Practice

This section is a formal statement of the BP Amoco Recommended Practice for collision avoidance, with which all Business Units are expected to comply. More general information and guidance on the application of particular methods is collected under 'Selected Topics' (➔ 4.4).

Background

The Recommended Practice is a revision of the 'BPX Anti-Collision Recommended Procedures', which were included as part 4 of the old BPX Directional Survey Handbook. Significant changes to that document are listed below.

The Recommended Procedures were not new when they were first issued (in 1996), they were merely a formal statement of the practices which had been developed and operated in BP's North Sea operations over many years, before being introduced world-wide. They may therefore be regarded as field-proven.

CHANGES FROM BPX RECOMMENDED PROCEDURES

Substantive changes between the old BPX Recommended Procedures and this Handbook are as follows (see main text for full details):

1. Minimum Separation – Major Risk Wells

   Old BPX rule:

   $$S = 2.58(\sigma_1+\sigma_2) + \min\{ 0.015\ DD, 15m \} + S_b$$

   Old Amoco NSDG rule:

   $$S = 4(\sigma_1+\sigma_2) + (d_1+ d_2) + S_b$$

   New BP Amoco rule:

   $$S = 3(\sigma_1+\sigma_2) + \tfrac{1}{2}(d_1+ d_2) + \min\{ 0.01\ DD, 10m \} + S_b$$

where

σ_1 = Planned well positional uncertainty at 1 standard deviation.

σ_2 = Interfering well positional uncertainty at 1 standard deviation. This must include any uncertainty in the relative surface positions of the planned and offset wells.

d_1 = Hole size in planned well.

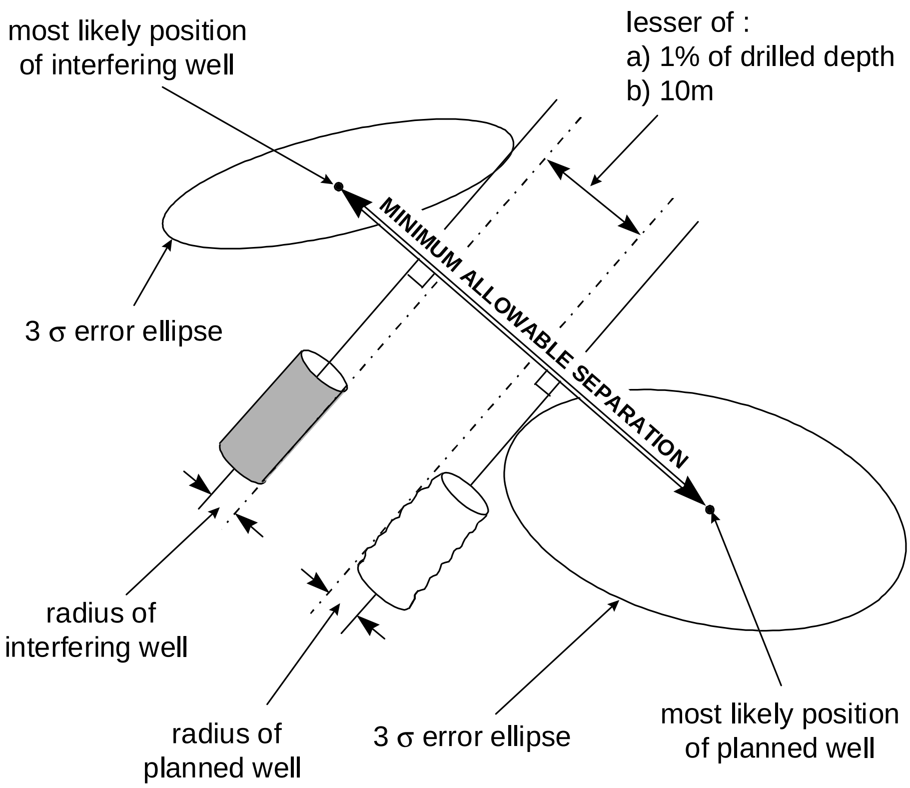
d_2 = Casing OD in interfering well.

S_b = Allowance for survey bias.

The new rule is intended to be safe, simple, and cost-effective to apply.

Figure 4.5

The minimum separation rule for major risk wells



2. Minimum Separation – Minor Risk Wells

   The BPX Procedures gave engineers the choice of either using a conventional separation rule, or a risk-based rule for minor risk wells. The new Recommended Practice eliminates the (unnecessary and wasteful) option of using a conventional rule, and obliges engineers to determine Tolerable Collision Risk for all minor risk wells.

General Requirements

All anti-collision planning and operations will be performed by competent personnel.

Specifically, the following personnel must have been assessed by a directional specialist as competent in the following skills:

	Performing anti-collision calculations	Drafting anti-collision diagrams	Using the anti-collision diagram for decision making while drilling
Well Planners	✓	✓	
Person responsible for 'signing-off' wellsite drawings	✓	✓	✓
Directional Drillers and DD Co-ordinators			✓
BPA Person responsible for 'drill ahead' decisions			✓

Table 4.1

Required competencies for anti-collision work

Where work is performed by a Contractor, it will be by written procedures which have been approved by BP Amoco.

All planning work will be completed prior to a section being drilled.

Deviations from these procedures will require a detailed Quantitative Risk Assessment (QRA) and formal sign-off by the BU Team Leader.

The Definitive Database

A definitive directional database will be maintained for every project or development.

The database will contain definitive surface and downhole locations for all wells and sidetracks within the vicinity of the project.

The number of personnel with the capability of modifying the data will be strictly limited.

The Clearance Scan

A clearance scan down the final proposed well trajectory will be performed against the definitive database or a validated copy thereof.

For a database to be used for the definitive clearance scan, there must be a process in place which ensures that it is, for practical purposes, identical to the definitive drilling database. It need only contain a subset of the wells in the definitive database, but must at least contain all the wells known to have been drilled in the area of interest.

Minimum Separation Criteria

The minimum allowable separation from each nearby well will be calculated at regular depth intervals using the criteria given below.

The separations are considered as distances measured perpendicular to the planned well, so that they lie in the plane of the anti-collision diagram. ‘3D’ or ‘minimum distance’ separations are more conservative, but cannot be adequately represented on the travelling cylinder plot and are therefore not part of the Recommended Practice.

CLASSIFICATION OF WELLS

Every nearby well detected by the clearance scan will be classified as presenting either a Major or a Minor risk.

The classification will be based on the following definitions interpreted for local conditions:

A nearby well presents a **Major risk** *if a collision with it would carry a significant risk to personnel or the environment. It presents a* **Minor risk** *if the risk to personnel and the environment in the event of a collision would be negligible.*

> The Major/Minor risk classification is preferable to the more prescriptive Flowing/Shut-in classification because it forces the engineer to think through the implications of collision in differing situations. For example, the consequences of collision with an oil-producer just above a shut-in SSSV should certainly be subject to a thorough risk assessment before the well is classified as Minor risk. Conversely, a collision with the same well in the perforated part of the reservoir section might well justify the Minor risk classification. Used in this sense, 'Minor' is a relative term – a well may be classified as Minor risk without implying that a collision with it would be of minor importance.

Where the risk classification changes down the length of the well, the depth of change will be clearly established.

> A well may present a Major risk for only a part of its length. For example, below the shut-in point, or more than a certain distance above the reservoir. Calculations involving the mud weight, shut-in pressure and fracture gradient may be required to establish at which depth the risk classification changes.

Risk classifications must be reviewed and endorsed by a competent drilling engineer

POSITIONAL UNCERTAINTY

Positional uncertainty in the planned and nearby wells will be calculated using either BP Amoco approved tool error models, or models derived from and validated against them.

The minimum allowable separation may be reduced by taking into account the ellipticity of the positional uncertainty. These calculations (➔ A.5) should only be performed by software which has been tested and approved by the UTG Technical Authority.

MINIMUM SEPARATION – MAJOR RISK WELLS

The minimum allowable separation from a Major risk well is:

Separation $= 3(\sigma_1+\sigma_2) + \frac{1}{2}(d_1+d_2) + S_b + 0.01\ \text{DD}$ (DD < 1000m)

$= 3(\sigma_1+\sigma_2) + \frac{1}{2}(d_1+d_2) + S_b + 10\text{m}$ (DD > 1000m)

where

σ_1 = Planned well positional uncertainty at 1 standard deviation.

➔ Section A.5 explains how relative surface position uncertainty is included in the minimum separation equation

σ_2 = Interfering well positional uncertainty at 1 standard deviation. This must include any uncertainty in the relative surface positions of the planned and offset wells.

d_1 = Hole size in planned well.

d_2 = Casing OD in interfering well.

S_b = Allowance for survey bias.

➔ Section A.5 explains how survey bias is included in the minimum separation equation

DD = Drilled depth (ie. the depth in the planned well measured from the Well Reference Point, usually mudline or ground level).

Example:	Planned well uncertainty at 1 std. dev. = σ_1 =	8 m
	Interfering well uncertainty at 1 std. dev. = σ_2 =	5.5 m
	Hole size in planned well = d_1 = 17.5" =	0.445 m
	Casing OD in interfering well = d_2 = 13.375" =	0.340 m
	Allowance for survey bias = S_b =	0 m
	Drilled depth = DD =	650 m

Separation = 3(8+5.5) + ½(0.445+0.340) + 0 + 0.01(650) = 47.4 m

MINIMUM SEPARATION – MINOR RISK WELLS

The minimum allowable separation will be calculated from:

$$\text{Separation} \quad = \quad \sigma\sqrt{2\ln\left(\frac{d_1+d_2}{R\sigma\sqrt{2\pi}}\right)}+\frac{1}{2}\left(d_1+d_2\right)+S_b$$

where:

$\sigma \ = \sqrt{\sigma_1^2+\sigma_2^2}$

$R \ =$ Tolerable Collision Risk

Example: σ_1, σ_2, d_1, d_2, S_b as above
Tolerable Collision Risk = R = 1 in 80 = 0.0125

$\sigma = \sqrt{[8^2 + 5.5^2]} = 9.71$ m
Separation = $9.71\sqrt{\{2 \ln [(0.445+0.340) / [(0.0125)(9.71)(2.51)]] \}}$
$+½(0.445+0.340) + 0 =$ 13.8 m

The risk-based separation equation exhibits some unexpected behaviour. In particular, it is meaningless when

$$\frac{d_1+d_2}{R\sigma\sqrt{2\pi}} \quad < \quad 1$$

This occurs when the relative position uncertainty of the planned and interfering wells is so large that the tolerable collision risk cannot be exceeded even if the planned well is drilled straight at the interfering well. The minimum separation In this case can be set to zero and no-go lines need not be drawn.

➔ For more on the behaviour of the risk-based separation equation, and its derivation, see A.5.

The Tolerable Collision Risk (TCR) will be derived from a consideration of the likely consequences of collision and the cost of reducing the risk and will be approved by the Business Unit.

➔ Section 4.4 gives guidance on determining Tolerable Collision Risk

For convenience, a risk level may be used which is less than the value determined from the cost-benefit analysis. Thus, for example, directional software might present a pick-list of rules based on risks of 1/10, 1/20, 1/50, 1/100, 1/200 and 1/500. A calculated TCR of 1/57 would indicate that the 1/100 risk-based rule should be applied.

MINIMUM SEPARATION – SIDE TRACK WELLS

For side-track and lateral wells, the position uncertainty used in the minimum separation calculations should – if the software allows it – represent the relative uncertainty between the drilling and parent wells.

Even when this is done, it is sometimes impractical to apply the standard minimum separations rules immediately below the kick-off point. In this case, good judgement must be used to determine from what depth the standard rules should be enforced.

The Anti-Collision Diagram

Drilling tolerances will be represented on an anti-collision diagram (a travelling cylinder plot annotated with tolerance lines). In exceptional cases, where drilling tolerances are so simple as to be adequately and clearly defined, they may be represented on plan view and/or vertical section plots.

It is occasionally possible to represent drilling tolerance lines adequately on plan view or vertical section plots, eliminating the need for an anti-collision diagram. For example, where there is no interference near surface, a single interfering well is involved, and the interfering well remains either above, below, or to the left or right of the planned well. Where there is any doubt that the drilling tolerances can be represented accurately, clearly and unequivocally in this way, an anti-collision diagram must be used.

The travelling cylinder plot will be centred on the final well plan with North (not Highside) at the 12 o'clock position.

Tolerance lines will be drawn on the diagram in such a way that violation of the minimum separation with any well and at any depth is a practical impossibility.

Use common sense when it is clear that a particular no-go line cannot be violated due to the presence of other, shallower drilling tolerances.

Anti-Collision While Drilling

Each anti-collision diagram will be shipped to the rig prior to the relevant section(s) being drilled.

Changes will not be made to the survey program without a review of the consequences for anti-collision.

Where the only deviations from the survey program are altered start and end depths to survey sections, it will usually be sufficient to recalculate the uncertainty in the planned well and to decide if the consequent changes in position uncertainty are significant. Eliminating surveys from the program, changing instrument types, or radically changing depth intervals will always require a full rework of the anti-collision calculations.

Survey procedures will be per the BP Amoco/Contractor Joint Operating and Reporting Procedures (JORPs) (➔ 5.10).

After each survey station is taken, the as-drilled position of the well will be marked on the anti-collision diagram.

INFRINGEMENT OF TOLERANCE LINES

Wellsite staff do not have permission to cross any tolerance line within the depth interval to which it applies.

In the event of a tolerance line being crossed inadvertently, or it being impossible to drill ahead without crossing a tolerance line, drilling operations will cease until the situation has been assessed by office-based staff.

When a tolerance line has been crossed, or is likely to be crossed if drilling continues, the situation must be assessed by the onshore drilling team. Firstly, the anti-collision diagram must be examined to confirm whether

either the tolerance can be relaxed without violating any no-go areas (for example if the line has been drawn to smoothly join two no-go areas),

or the tolerance line protects only planned well(s) and there is sufficient room to safely re-plan these at a later date.

In either case, an amendment to the anti-collision diagram with the tolerance line moved to allow drilling ahead can be prepared. If only a small section of the diagram is affected, it may be faxed to the rig.

It is always better to provide the rig with a revision to the anti-collision diagram than with verbal or written instructions. It will usually only be possible to relax a tolerance line by a limited amount, over a limited extent of the diagram. This information is difficult to convey in words.

If the tolerance line protects an existing well, the options to be examined include:

- Plug back and side-track
- Re-survey with a more accurate tool
- Perform a QRA analysis to justify drilling ahead
- Drill ahead with increased survey frequency and alertness (this may be appropriate where a tolerance line is just being ‘grazed’)

4.4 Anti-Collision – Selected Topics

The Travelling Cylinder

The Travelling Cylinder is a mathematical projection used for collision avoidance. The planned trajectory is represented as a point at the centre of a disk, onto which are plotted the paths of nearby offset wells. The following diagram shows how an offset well appears:

For more information on the Travelling Cylinder and its uses, see **IADC/SPE 19989 The Travelling Cylinder: A Practical Tool for Collision Avoidance**

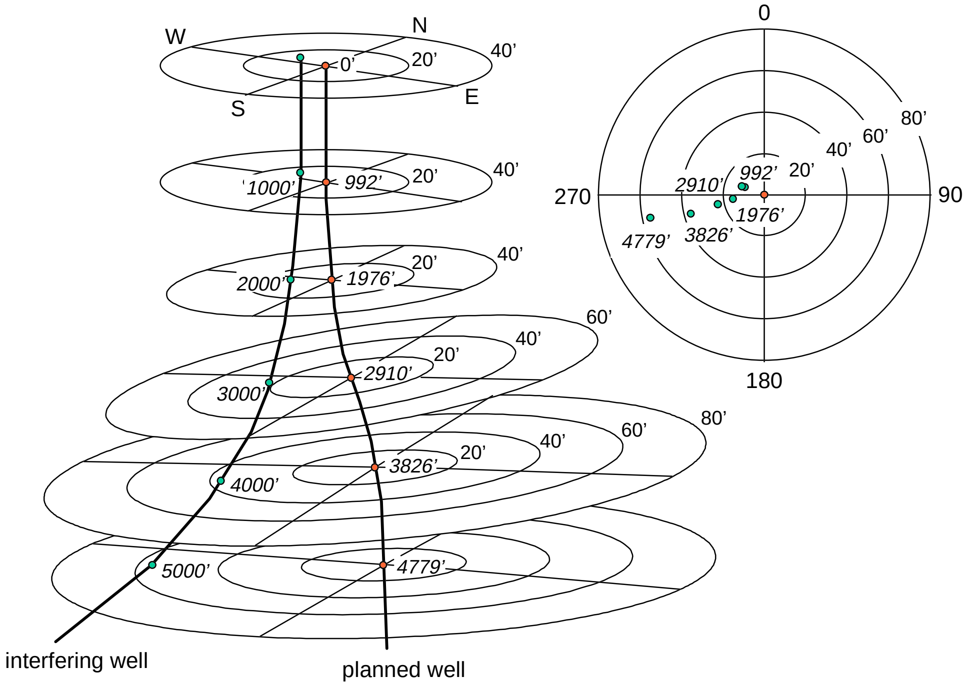


Figure 4.6

How a nearby offset well appears on a travelling cylinder

REFERENCE SURVEY

It is a BP Amoco Standard Practice to plot the travelling cylinder with the proposed trajectory at the centre. This prevents the need for replotting as drilling progresses. Software which puts the as-drilled trajectory at the centre should not be used.

! BP Amoco Standard Practice

REFERENCE DIRECTION

! BP Amoco Standard Practice

It is a BP Amoco Standard Practice to plot the travelling cylinder such that at all depths, the proposed well azimuth on the plot represents the well highside direction. This is commonly known as a North-referenced travelling cylinder, or as 'BP North'. Software which plots the well highside direction at 12 o'clock should not be used.

There is nothing fundamentally wrong with highside-referenced travelling cylinder diagrams, and in most situations they are safe to use. The superiority of the North-referenced projection becomes evident at low well inclinations, where the highside direction in the planned well may change rapidly (for example when nudging away from other wells). These rapid changes cause discontinuities in the traces of interfering wells on the diagram, which may make the drawing of adequate tolerance lines impossible.

TRAVELLING CYLINDER CO-ORDINATES

A point on a travelling cylinder is specified by two co-ordinates. The **radial distance** is the distance from the centre of the anti-collision diagram. Physically, it is the perpendicular distance from the well plan. The **relative azimuth** is the angular co-ordinate on the anti-collision diagram. Physically, it is the angle clockwise from the well plan highside plus the well plan azimuth. When the well is vertical, or nearly vertical, it is the (drilling grid) bearing from the planned well.

Any plotted point on a travelling cylinder is meaningless without an accompanying **relative depth.** This is the survey depth measured down the well plan and represents the amount of progress made against the plan. Use of the relative depth (rather than measured depth) is necessary for direct comparison with depth labels on tolerance lines. In most cases, the relative depth is very close to the measured depth, but users of the diagram should be aware of the distinction.

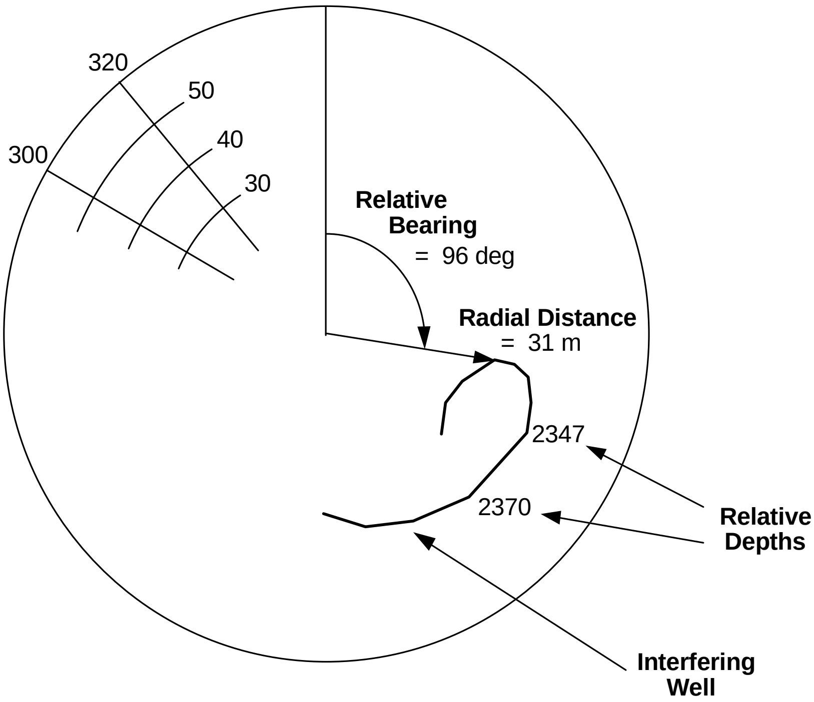


Figure 4.7

Travelling cylinder co-ordinates

NO-GO AREAS AND TOLERANCE LINES

The advantage of the travelling cylinder diagram over any other projection is it's ability to accurately display drilling tolerances. Around any point on an offset well, a shape may be drawn which represents the minimum approach distance to that well at that depth according to the anti-collision rule in force. Since the minimum distance may vary depending on the angle at which the wells approach, this shape, called a **no-go area**, will generally not be circular.

Drawing no-go areas around every point on every offset well on a travelling cylinder will quickly result in a hopelessly confused plot. For this reason, **tolerance lines** are drawn which summarise the information contained in the 'no-go' areas. In general, each tolerance line represents the shape obtained by combining all the no-go areas at a given depth. The tolerance line is then labelled with this depth.

For a step-by-step guide to drawing tolerance lines and completing anti-collision diagrams, see **How to Draw an Anti-Collision Diagram** by Hugh Williamson, UTG Well Integrity Team

DRAFTING TOLERANCE LINES

The following figure shows some useful conventions for summarising no-go areas with tolerance lines.

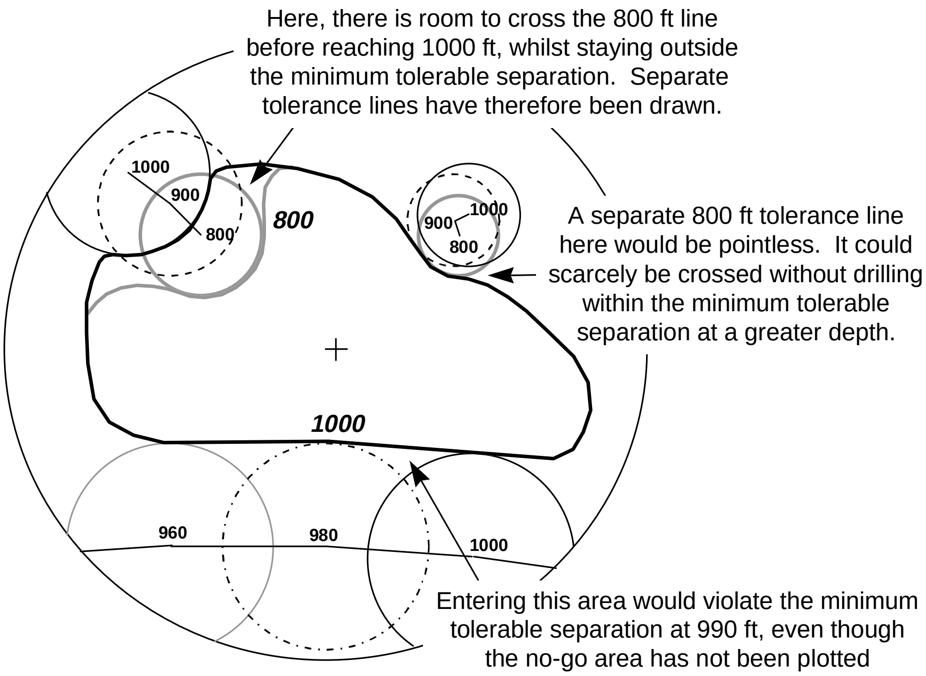


Figure 4.8

Rules and conventions for drafting tolerance lines

Tolerable Collision Risk

Tolerable collision risk (TCR) is the value of collision probability which is used to determine minimum well separation for a close approach between wells. It represents the maximum probability of collision considered acceptable for a particular close approach. A worksheet is available to help the engineer derive a reasonable and defensible value of this probability whatever the circumstances.

➔ The worksheet, plus 3 completed examples, is in Appendix C.

Tolerable collision risk is a function of:

a) The cost of the likely consequences of collision (*C* on the Worksheet).

b) The cost of substantially reducing or eliminating the risk (*V* on the Worksheet).

c) The confidence in the QRA decision-making process.

d) Natural risk aversion.

(a) and (b) determine the primary inputs to the calculation of the Tolerable Collision Risk, and if they alone were considered, its calculated value would be (*V/C*). However, each BU is likely to wish to build some inequality into the calculation, to ensure that when the well is planned on the basis of accepting the TCR (rather than reducing the risk of collision) the economics supporting the decision are overwhelming, not just marginal. A reduction by a factor of 20 in the Tolerable Collision Risk due to the combined effect of (c) and (d) is built into the worksheet. When the risk-based rule is applied in a more finely balanced situation, the factor *M* can be reduced (or *F* can be increased depending on which branch of the worksheet flow diagram is taken).

Each qualitatively different collision risk scenario will justify a separate Tolerable Collision Risk, and hence require a separate Worksheet. In general, three factors will determine the scenario:

- The type of interfering well (oil producer, water injector, plugged and abandoned etc.)
- The depth of interference (above SSSV, below surface casing shoe, in reservoir etc.)
- The possibilities (if any) for reducing the risk (none feasible or a requirement for extra directional work)

The worksheet takes the engineer through the information gathering and calculation process, leading to a clear, understandable result. It can then be reviewed and approved by drilling management. The examples in Appendix C include a variety of ways of completing the cost and benefit sides of the equation. All are valid.

For more on the practical limitations of QRA applied to anti-collision see **SPE 36484 Towards Risk-Based Well Separation Rules**

Quantitative Risk Assessment must not be applied to Major risk wells. The imperfect knowledge of survey tool performance, and the inability to eliminate occasional human error from the anti-collision process makes the application of QRA to risks with safety and environmental implications problematic. We do not currently have the knowledge or processes to be able to assure the tolerability of the risks resulting from such an application of the technique.

Single Wire Magnetic Ranging

For more information see **IADC/SPE 39389 Collision Avoidance Using A Single Wire Magnetic Ranging Technique at Milne Point, Alaska**

SWMR is a technique originally developed for the drilling of relief wells, which has been adapted for collision avoidance. It is patented by Vector Magnetics Inc. of Ithaca, New York. The applicable US patent numbers are 5,485,089; 5,515,931 and 5,657,826. Exclusive rights for the single wire method are currently licensed to Sperry-Sun/Halliburton.

PRINCIPLE

A magnetic field is induced around the well to be avoided by running a current through a conductor within the well. This field is detected by a MWD tool in the drilling well. Best results are obtained when the MWD tool is configured to take pumps-off surveys. A simple calculation yields the separation and relative direction of the wells.

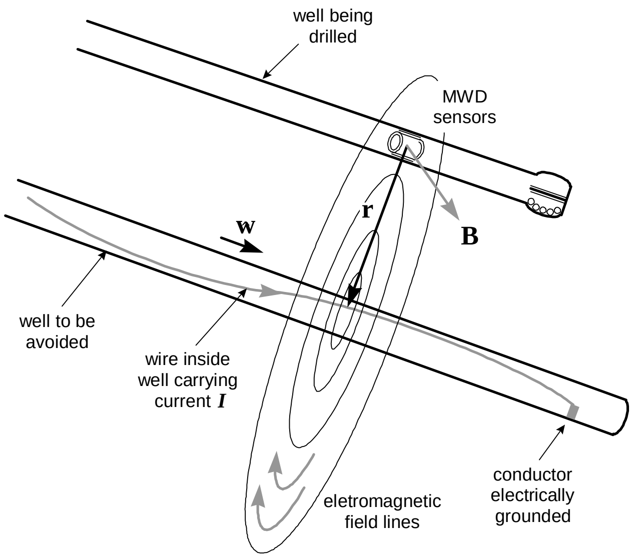


Figure 4.9

Principle of single wire magnetic ranging

If the completion in the interfering well has no suitable conductor, a standard electric logging cable may be used. The end of the cable should be earthed by electrical contact with the wellbore at its deepest point. If possible, the cable should be run at least 300m (1000ft) past the point of close approach to minimise end effects. The decision to flow, shut-in or kill the interfering well should be made on a case-by-case basis following a risk assessment.

A fix on the interfering well is determined from two MWD surveys, with the current direction being reversed between them. Differencing the magnetometer readings for the two surveys eliminates the Earth's magnetic field from the measurements, leaving just the field, **B,** induced by the current in the wire. This field is related to the vector, **r**, from the MWD sensors to the perpendicular point in the interfering well, by Ampere's Circuital Law, $\mathbf{B} = \frac{\mu_0 I}{2\pi|\mathbf{r}|^2}(\mathbf{r} \times \hat{\mathbf{w}})$ where $\hat{\mathbf{w}}$ is the unit direction vector in the interfering well. The vector **r** may be determined by making it the subject of the equation: $\mathbf{r} = \frac{\mu_0 I}{2\pi|\mathbf{B}|^2}(\hat{\mathbf{w}} \times \mathbf{B})$.

APPLICATIONS AND PERFORMANCE

SWMR has its main application where well congestion precludes compliance with standard BP Amoco well separation rules. It is most likely to be cost-effective when the interfering well (or wells) cannot be shut-in below the point of close approach without major intervention. Special care should be taken when an interfering well is approached at a high angle of incidence and there is consequently less time for fine-tuning the close approach.

The range and accuracy of the method are both dependent on the current in the conductor, which should be maximised within safe limits, and the resolution of the MWD measurements. When electric line is used as the conductor, and a 12 Amp current is used, errors of ±4 ft at 100 ft and ±15 ft at 200 ft may be expected, with a maximum range of about 250 ft.

It is strongly recommended that UTG be involved at an early stage where use of this method is contemplated.

4.5 Target Analysis

Typically, the geological objective of a well is defined in terms of an area or volume of rock which the bit must penetrate. In the case of a volume, there may be a further requirement that the well remain within the volume for a certain minimum course length. Due to the presence of survey uncertainty, we can never be 100% certain that our geological objective has been met. We can increase our confidence by

a) Increasing the accuracy of the survey program.

b) Instructing the directional driller to penetrate the target close to it's centre.

Each of these has an associated cost. (a) will entail a direct charge for additional survey services and extra rig-time for running them. (b) will usually require additional steering and may even necessitate a sidetrack. There is an inevitable compromise between incurring these costs and increasing the geological risk. Resolution of this compromise through quantitative calculation is called **target analysis**.

Driller's Targets

The part of the geological target into which the directional driller must steer the bit in order to allow sufficiently for survey uncertainty is called the **driller's target**. In figure 4.10a suppose that surveys indicate the well has penetrated the geological target at the point shown. Given the survey uncertainty represented by the error ellipse, 100 repeat surveys of the well to the same accuracy might indicate the penetration points shown in figure 4.10b.

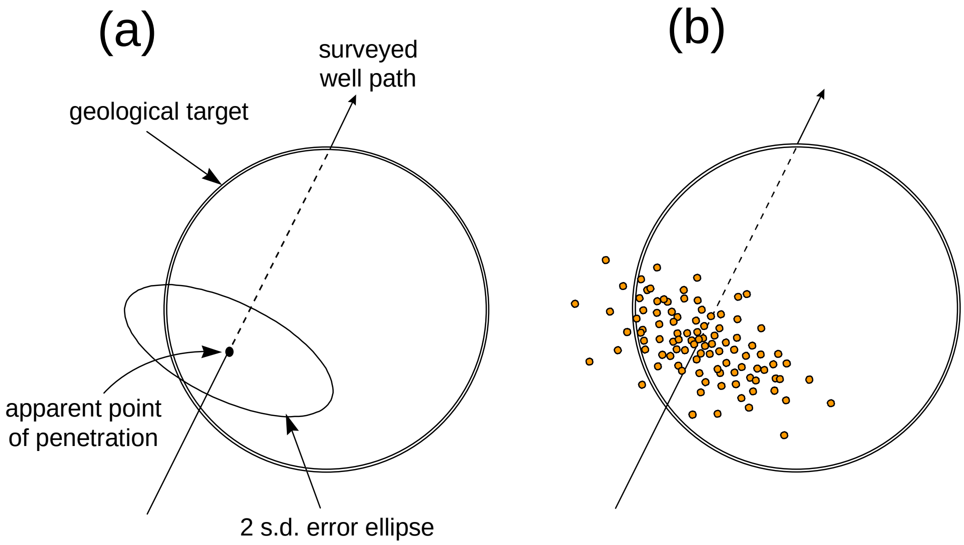


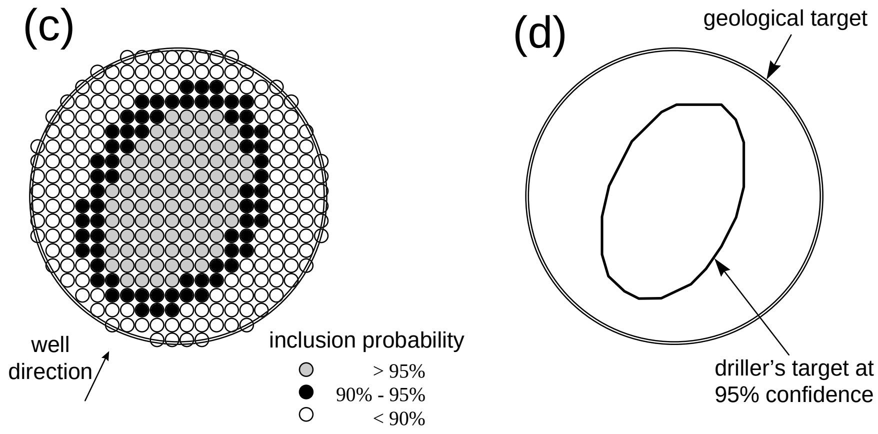
Figure 4.10

Calculation of the driller's target

Eight of the 100 surveys show the well failing to penetrate the geological target. We say that our original point of penetration in the geological target has an inclusion probability of 92%. Colour coding all interior points in the geological target according to their inclusion probability gives a picture like 4.11c.

Figure 4.11

Calculation of the driller's target (contd.)



Finally, we define that area of the geological target within which the inclusion probability is at least, say, 95%, as the 'driller's target at 95% confidence'. This is shown as a simple boundary in 4.11d, and should be represented as such on all drilling plots.

Defining a Confidence Level

The drilling engineers and well planners in each Business Unit should make sure their geologists and geophysicists understand about driller's targets, and should involve them as far as possible in resolving the compromise described above. In many cases, the survey uncertainty is much smaller than the dimensions of the geological target, and the driller's target may be defined at a high confidence level (eg 99%), without incurring any directional drilling difficulty. For small geological targets, extended reach wells, and near-horizontal approach angles (see below), this may not be the case. Circumstances will vary, but the alternative means of increasing the size of the driller's target should be considered in roughly the following order:

a) Discuss extending the geological target with the geologists.

b) Enhance the survey program to reduce position uncertainty.

c) Change the well profile to lessen the approach angle.

d) Agree on a reduced confidence level of target penetration with the geologists.

Confidence levels of 95% or 90% should be broadly acceptable if they really are required. Driller's targets should only be defined at less than 90% confidence once every alternative has been explored. In extreme cases, the viability of the well may have to be seriously questioned.

Effect of Approach Angle

The size of the driller's target is determined by the 'bit's-eye-view' of the geological target boundary. Most target boundaries are defined on a horizontal plane and are therefore easier to hit when approached at a low inclination, when foreshortening is a minimum. At the opposite extreme, it is impossible to hit a horizontal plane target with a horizontal well.

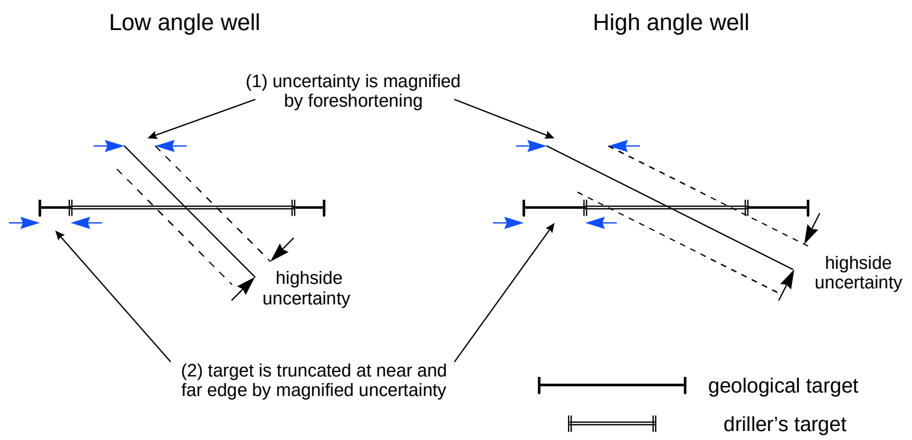


Figure 4.12

Effect of hole angle on size of driller's target (side-on view)

As well inclination increases, more and more of the geological target must be truncated at the front and back edges due to the magnifying effect that foreshortening has on the highside survey uncertainty. The exact relationship, and a useful rule-of-thumb is:

amount of target truncated at front & back

= highside uncertainty / cos (incl)

For uncertainty quoted at two standard deviations, this rule will give a driller's target at about 98% confidence.

Calculation of the Driller's Target

➔ The BP Amoco algorithm and the graphical method are described in Section A.4

Most target analysis calculations will be done automatically by directional software. BP Amoco has developed an algorithm for this which takes full account of the survey uncertainty and the geometry of the target.

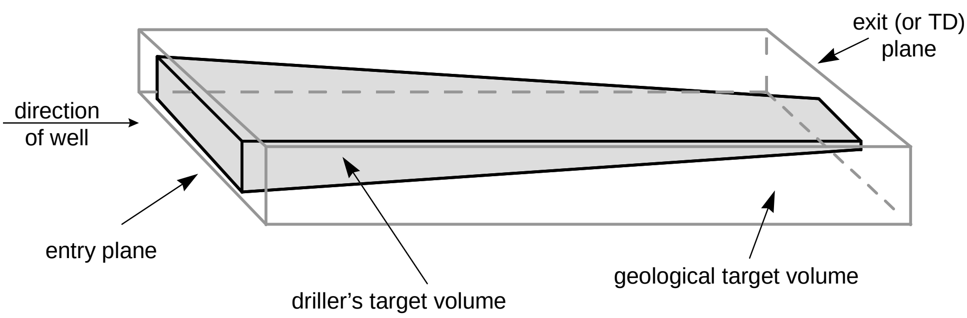
Should the need arise, it is entirely possible to calculate a driller's target with the aid of a pocket calculator and graph paper. The method is simple enough to use as a quick check on the automatic calculations.

Target Analysis for Horizontal Wells

Because of the foreshortening effect when approaching at high angle, targets for horizontal wells cannot be defined as horizontal shapes. The usual practice is to define the geological target in the form of a solid slab. The front plane represents the reservoir entry point, and the end plane the exit point, or planned TD of the well. Driller's targets may be computed for both these planes, and the respective corners joined, forming a driller's target volume as illustrated below.

Figure 4.13

Driller's target volume for a horizontal well



If the reservoir section is long enough, the vertical or lateral uncertainty may be sufficient to cause the driller's target to 'pinch-out'., as shown below. This is an indication that the geological positioning tolerances cannot be met by surveying alone. It may still be possible to achieve the objectives by geosteering.

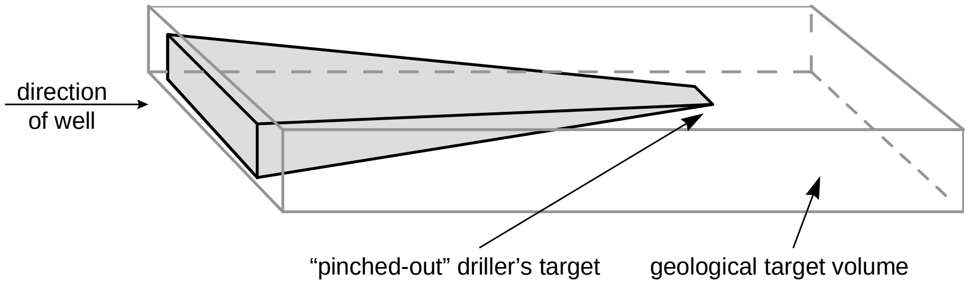


Figure 4.14

Pinched-out driller's target – a case for geosteering

4.6 Survey Calculation

There is an extensive literature on the comparatively straightforward operation of calculating well position (typically North, East, TVD), from survey tool measurements (measured depth, inclination, azimuth). The ubiquity of the computer has meant that avoidance of computational complexity is no longer of prime importance, and the method which is generally considered the most accurate, even though it is amongst the most complex, has been widely adopted throughout the Industry. This is the method of **minimum curvature**, which assumes a spherical arc (or straight line) between successive survey stations.

➔ The minimum curvature equations are given in Section A.1

It is a BP Amoco Standard Practice to use the minimum curvature method for all well position computations. Alternative methods such as 'radius of curvature', 'average angle' and 'balanced tangential' are still seen from time to time, particularly on historical data, but their continued use should not be encouraged. They are less accurate than minimum curvature, and their use in conjunction with integrated directional software gives rise to inconsistencies in such applications as interpolation and close-approach calculations, both of which assume circular arcs between stations.

! BP Amoco Standard Practice

Reverse Survey Calculation

The problem of back-calculating along-hole depth, inclination and azimuth from survey station co-ordinates is known as reverse survey calculation, or survey back calculation. It may occur in relation to inertial data, or when a well trajectory must be reconstructed from co-ordinate data alone. Unfortunately, direct inversion of the minimum curvature survey equations is not practical, and leads to unstable solutions. A more robust method, which gives results precise enough for most purposes, is included in Section A.1.

4.7 In-Hole Referencing

In-hole referencing (IHR) is a survey and data processing technique designed to eliminate two of the major systematic errors inherent in MWD surveys. Its use is restricted to tangent (ie. straight) hole sections, but it has been used extensively both in the North Sea and more recently in Alaska.

Principle of IHR

In-hole referencing works by comparing the results of MWD and gyro surveys over an interval of overlap, and deriving an azimuth correction which is applied to subsequent surveys taken with the MWD. The assumption is that the two major sources of error in the MWD azimuth measurements – magnetic declination and axial drill string interference – are systematic over a single bit run so long as the hole direction doesn't change. A correction to one MWD survey derived from direct comparison with a more accurate survey will then be applicable to all surveys taken with the same MWD/BHA combination.

Applicability of IHR

In-hole referencing is normally only be applied over hole intervals where

- The inclination is everywhere greater than 20°
- A constant azimuth is maintained over a suitable 200ft interval below the casing shoe (this will be the IHR interval – see below)
- The combined change in inclination and azimuth over the section does not exceed a pre-determined amount (see 'Maximum Change in Hole Direction' below)

In-hole reference corrections must not be applied to inclinations. In most cases, an MWD or electronic multishot inclination properly corrected for BHA sag will be at least as accurate as one corrected to agree with a gyro run in drill-pipe or open hole.

In-hole referencing should only be applied to solid-state magnetic survey devices (MWD and electronic multishots). It must never be applied to camera-based survey tools, which do not have the necessary reliability or accuracy.

Important Caveat

In-hole referencing has one major disadvantage over other survey methods. It obscures the surveyor's most valuable insight into data quality and integrity – comparison of independent surveys. Any error in the gyro reference survey will be propagated down the well and will be undetectable from a comparison with the corrected MWD data.

➔ Survey data comparison is described in Section 4.10

It is vital that all IHR corrections are checked for reasonableness as well as numerical accuracy, and that unusually large or highly correlated corrections are investigated by a survey specialist.

IHR Procedures

These procedures are to be used when it is anticipated that the tangent section will take several bit runs to complete. When there is a realistic probability of drilling the section with a single bit run, the modified procedures which follow should be applied.

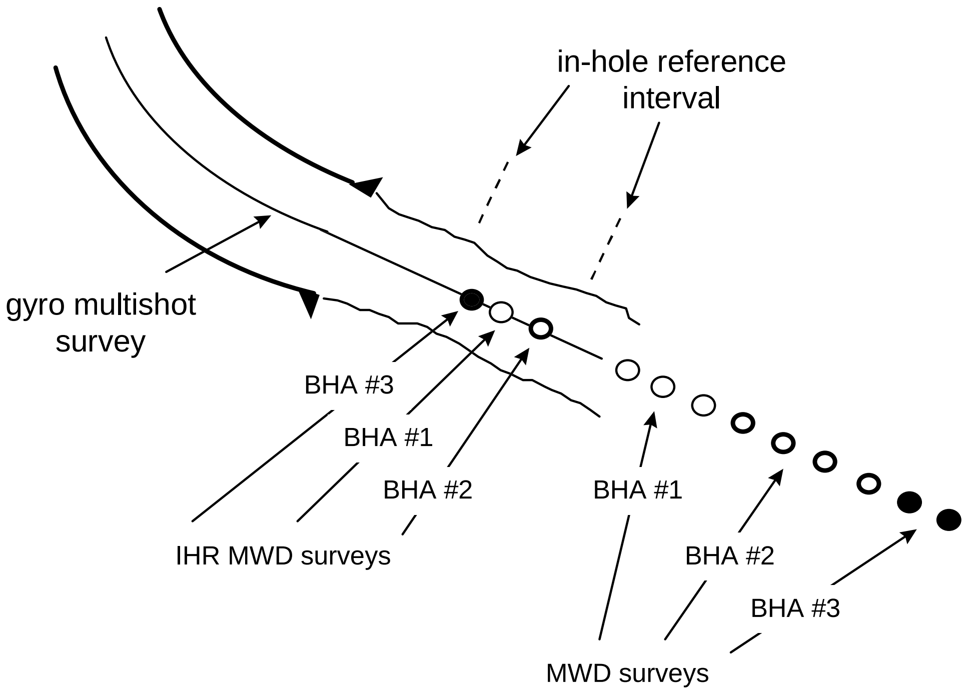


Figure 4.15

In-hole referencing – section drilled with multiple BHAs

1. Between 500 ft (150m) and 1000 ft (300m) of tangent section are drilled below the previous casing shoe. This section should be designed and drilled in a way which maximises the chances of obtaining a suitable in-hole reference interval (see below). Where a steerable assembly is in use, it may be worth rotating over a 200 ft section to ensure the required smoothness is achieved. The MWD survey interval may be left unchanged while drilling this section below the casing shoe.

2. A north-seeking gyro multishot survey is run to TD of the open hole section. This usually requires that the tool be pumped down the drill string (the practice of running tools into open hole has virtually ceased due to increased tangent angles and the risk of getting stuck). Survey stations should be recorded every 25ft or 10m over the open-hole section. This survey is called the **reference survey**.

3. Once the survey results are available an **in-hole reference interval** is identified over which tool comparisons are to be made. This interval should:

   a) Be far enough below the casing shoe to effectively eliminate the possibility of magnetic interference. 250ft (75m) is a recommended minimum.

   b) Be at least 200ft (60m) in length.

   c) Show azimuth variations of no more than 0.5° between survey stations.

   There is no restriction on build/drop rates over the IHR interval, but see 'Maximum Change in Hole Direction' below.

4. At the start of each bit run, when tripping in, an MWD survey is taken within the IHR interval. Two surveys should be taken, with a toolface change between them of at least 90°, and the average azimuth used in the correction calculation.

   A different depth in the IHR interval should be selected on each bit run. This helps randomise any residual errors. To avoid unnecessary calculation (interpolation of the gyro survey), it is easiest if each MWD survey is taken at exactly the depth of a gyro station.

5. An azimuth correction is calculated (see below) and applied to all subsequent surveys taken by that MWD/BHA combination within the tangent section.

CALCULATION OF IHR CORRECTIONS – MULTIPLE BHAS

Where the tangent section is drilled in several bit runs, the IHR correction for each BHA is calculated by comparing a single MWD station azimuth with the reference survey azimuth at the same depth. The following table is an example:

Table 4.2

Calculation of in-hole reference corrections – section drilled with multiple BHAs

Measured Depth	Gyro Azimuth	MWD Azimuth	BHA #	Interpolated Gyro Azimuth	IHR Correction	Corrected MWD Azimuth
1250	**271.62°**					
1275	**271.81°**					
1300	**271.77°**					
1325	**272.04°**					
1350	**272.16°**					
1315*		272.7°	1	**271.93°**	-0.77°	271.93°
1413		273.6°	1		-0.77°	272.83°
1508		274.1°	1		-0.77°	273.33°
1604		274.3°	1		-0.77°	273.53°
1255*		272.1°	2	**271.66°**	-0.44°	271.66°
1699		274.2°	2		-0.44°	273.76°
1793		274.7°	2		-0.44°	274.26°
1300*		272.9°	3	**271.77°**	-1.13°	271.77°
1886		276.1°	3		-1.13°	274.97°
1980		276.2°	3		-1.13°	275.07°
2073		276.5°	3		-1.13°	275.37°

* In-hole reference station

RETROSPECTIVE CORRECTION OF MWD SURVEYS

It may be possible to apply an azimuth correction retrospectively to all the surveys taken with the BHA used to drill the IHR interval. If there is more than one MWD survey station within the IHR interval, the azimuth corrections for each should be calculated and an average figure applied to the remainder of the bit run.

MODIFIED PROCEDURES FOR SINGLE BHA SECTIONS

When it is likely that the entire tangent section will be drilled with a single BHA, extra precautions must be taken to ensure that the IHR correction is valid:

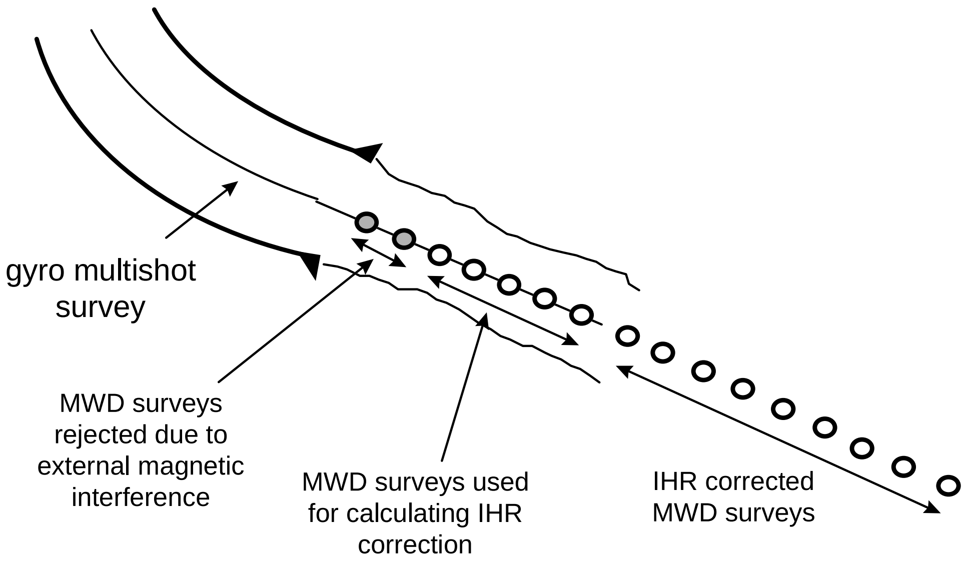


Figure 4.16

In-hole referencing – section drilled with single BHA

1. Instead of restricting the comparison to a 200ft interval, the IHR correction should be derived from as many MWD surveys as possible. The following MWD surveys should be excluded from the comparison:

    - Any MWD surveys which show evidence of external magnetic interference (to be expected near the casing shoe)

    - Any MWD surveys taken at depths where the reference survey exhibits rapid changes in azimuth (>0.5° between stations)

    - Any MWD surveys which indicate an IHR correction which is unequivocally different to the general trend

2. The reference survey should be interpolated at the depths of all the remaining overlapping MWD stations, and an average correction calculated.

3. This correction should be applied to all surveys taken with the BHA.

4. Should further BHAs be run, the surveys may be IHR corrected by following the usual procedures.

The following table shows how a single BHA is IHR corrected:

Table 4.3

Calculation of in-hole reference corrections – section drilled with a single BHA

Measured Depth	Gyro Azimuth	MWD Azimuth	Interp. Gyro Azimuth	Azimuth Diff.	IHR Correction	Corrected MWD Azimuth
6200*	**83.23°**					
6300	**83.06°**					
6400	**82.69°**					
6500	**82.24°**					
6600	**82.38°**					
6700	**81.60°**					
6800	**81.45°**					
6276		82.1°	**83.10°**	1.00°		
6370		81.6°	**82.80°**	1.20°		
6467		81.3°	**82.39°**	1.09°		
6562		82.2°	**82.33°**	0.13°	reject †	
6655		81.1°	**81.95°**	0.85°	reject ‡	
6749		80.7°	**81.53°**	0.83°		
				mean	**+1.03°**	
6842		79.9°			+1.03°	80.93°
6936		79.1°			+1.03°	80.13°
7030		77.9°			+1.03°	78.93°
7125		78.0°			+1.03°	79.03°

* For illustration only – reference survey interval should be 25 ft or 10 m.
† Rejected – statistical outlier.
‡ Rejected – azimuth change between reference survey stations >0.5° (Azimuth change between 6600 ft and 6700 ft = 81.60° – 82.38° = -0.78°).

MAXIMUM CHANGE IN HOLE DIRECTION

In-hole referencing relies on the assumption that the systematic azimuth errors affecting MWD remain the same throughout a bit run. This is true for magnetic declination errors due to crustal anomalies, but is only true for axial drill string interference so long as the hole direction does not change. The maximum permissible change in hole direction depends on the initial hole direction. The following condition for acceptable direction change assumes that the non-magnetic spacing of each MWD meets the specifications in Section 4.9 for all applicable hole directions:

Max. change in sin(Inclination)sin(magnetic Azimuth) $\leq \pm 0.25$

Example A proposed IHR section starts at 65° inclination, 150° magnetic azimuth, and finishes at 75° inclination, 130° magnetic azimuth.

Is this change in hole direction acceptable ?

Answer sin(65°)sin(150°) - sin(75°)sin(130°) = 0.45 - 0.74 = 0.29

The change in hole direction is too great, and IHR cannot be applied over the whole section.

IN-HOLE REFERENCING OF ELECTRONIC MULTISHOTS

Electronic multishots are in-hole referenced in much the same way as MWD when a single BHA is used. An azimuth correction is computed from the entire overlap interval with the reference survey, after surveys exhibiting external magnetic interference and statistical outliers have been eliminated.

4.8 In-Field Referencing

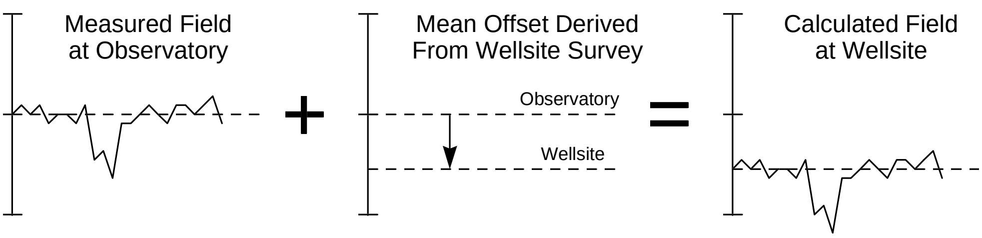
For a complete discussion of interpolation in-field referencing, see **SPE 30452 Reduction of Well-Bore Positional Uncertainty Through Application of a New Geomagnetic In-Field Referencing Technique** and **SPE 49061 Application of Interpolation In-Field Referencing to Remote Offshore Locations**

All magnetic surveys require an estimate of the direction of magnetic north at the drill site. Depending on the data processing applied, some also require an estimate of the magnetic dip angle and field strength. Normal practice is to obtain these estimates from a global model of the geomagnetic field such as the British Geological Survey Global Geomagnetic Model (BGGM). However, global models are designed to provide estimates of main field only. The contributions of the crustal and disturbance fields are effectively errors when a geomagnetic model is used to estimate the local field (➔ 3.2).

Ideally, magnetometers would be situated at the drill site to measure the local strength and direction of the magnetic field continuously and with high accuracy. This has rarely proved to be a realistic proposition. The technique of interpolation in-field referencing (IIFR) has been developed to provide a practical approximation to the ideal. IIFR combines a local one-off absolute measurement of the geomagnetic field with continuous measurements made at one or more remote magnetic observatories to estimate the local values of the magnetic field. In effect a 'virtual' magnetic observatory is run at the site, taking advantage of the stringent quality control procedures applied at the remote observatories.

Figure 4.17

The IIFR principle



Magnetic Field Modelling

On land, an accurate ‘snapshot’ of local magnetic field can be obtained using standard land survey techniques – an observer equipped with a tripod, a non-magnetic theodolite and a proton magnetometer is all that is required. Offshore, a stable, non-magnetic environment is less easy to find. The solution adopted to date has been to make use of the aeromagnetic data usually acquired for geophysical exploration.

These aeromagnetic data sets typically consist of closely-spaced spot measurements of magnetic field made using an instrument which measures only the total field strength. The data collected are corrected for time-varying fields by reference to measurements made by a magnetometer operated at a base station. An estimate of the main field is then removed, often using a global geomagnetic field model. The remaining signal is in effect a crustal anomaly map. The mathematical transformation of this total intensity data into three-element vector data is based on a number of broad assumptions concerning the source and nature of the crustal field. The two most limiting are:

a) The anomaly in field intensity is harmonic. This is true provided the direction of the main field is constant over the area of the aeromagnetic survey.

b) The data points are collected on a horizontal surface. Aeromagnetic surveys offshore are flown at a well-defined altitude, approximating a horizontal surface.

These two assumptions mean that areas greater than about 50km by 50km must be split be into smaller sections and analysed individually.

The magnetic anomaly map produced in this way should be examined carefully and local geological information used to assess the likelihood of the presence of significant shallow magnetic sources. Where such sources exist, extrapolating the crustal component values computed at the aircraft altitude to the sub-surface environment may lead to significant errors.

In-Field Referencing Operations

IFR is unlike other survey services. It requires co-ordination and communication of a consistently high quality, and vigilance on the part of experienced and knowledgeable staff. This section gives some guidance based on experience.

VALIDATION OF MAGNETIC FIELD VALUES

Since the magnetic field values obtained from the anomaly map are not the result of direct observation and rely on the validity of several assumptions, they must be validated by independent techniques prior to use. This is typically done by comparing IIFR corrected MWD surveys with high accuracy inertial grade downhole gyro surveys. There are three variations on this method, all of which have been used to good effect:

- Run gyros in the first one or two wells drilled after the magnetic mapping exercise
- If gyro surveys have been taken in previous wells, and if suitable MWD data are available, re-process the data and compare results retrospectively
- Compare IIFR MWD azimuths with in-hole referenced MWD azimuths (➔ 4.7)

APPLICATION OF IIFR DATA

At a basic level, the application of the IIFR technique is simple. The rig drills ahead correcting its surveys for declination only. These are replaced with a batch of IIFR corrected surveys as and when required.

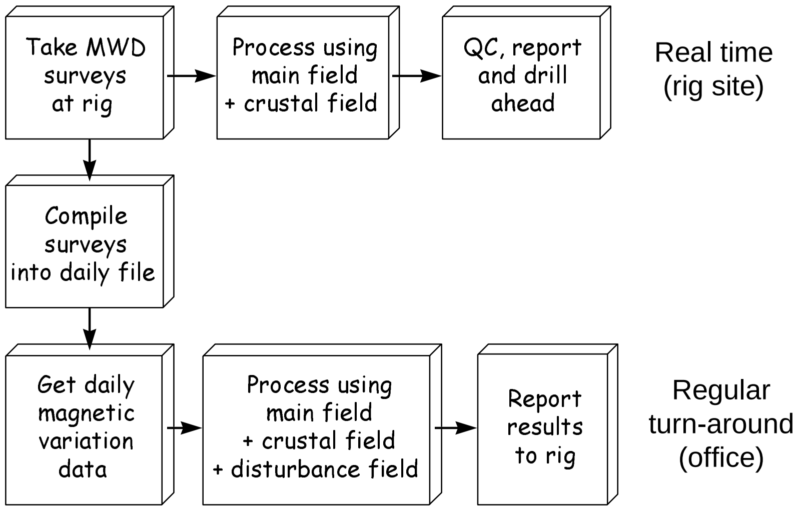


Figure 4.18

Typical process sequence in an IIFR operation

Knowledge of the crustal anomaly at the drill site benefits the real-time survey data in two ways. First, a more accurate declination value may be used for correcting data at the rig. To avoid confusion, a single value is normally adopted for the whole well, but for some extended reach or deep wells use of more than one value may be justified. Second, improved estimates of total field strength and dip angle allows better real-time magnetic data quality control to be applied on the rig.

All MWD surveys acquired on the rig are compiled into a file and sent to the processing centre, typically on a daily basis. Each survey must be time-stamped using a time base synchronous with the magnetic observatory data. Except during magnetic disturbances, particularly at high latitudes, synchronisation accurate to +/- 1 minute is sufficient, and may be achieved by the MWD/Survey engineers using a broadcast radio signal. For quality control purposes it is important that the six-axis accelerometer and magnetometer data be supplied for full analysis using triaxial bias and scale factor error evaluation techniques.

OPTIONS FOR DATA PROCESSING

There are several options of applying local field models and observatory data to magnetic wellbore surveys which can be described as IIFR. The simpler methods give the most rapid turn-around time and require the least complex technical assurance. The more advanced methods offer the potential of greater accuracy, but at the expense of greater computational and logistical complexity. Typically, an operation will need to select two correction methods: one for instantaneous application at the rigsite to enable drilling ahead, and one for production of definitive wellbore position data. The recommended options for azimuth correction are as follows.

OPTION 1 *Correction for crustal field declination*

The magnetic declination at the drill site as determined from the magnetic anomaly map is used in preference to the value predicted by a main field model to correct magnetic survey azimuths. Since this value represents a snap-shot in time, its accuracy will quickly degrade unless it is corrected for secular (ie. long-term) variation in the field. This may be done by calculating the declination anomaly (ie. the difference between the true value and the main field value) at the time of the observations, and adding this value to all subsequent main field model predictions.

OPTION 2 *Correction for crustal field declination and drillstring interference*

Surveys are corrected for axial magnetic interference using the values for magnetic field strength and dip as determined from the magnetic anomaly map. These corrections may be applied with confidence to surveys over a greater range of hole orientations than is the case when only a main field model is available. Only orientations within a few degrees of horizontal east-west need be excluded. Estimates of magnetic field strength and dip angle at the drill site should be made as in Option 1 and updated for each well drilled.

<u>*OPTION 3*</u> ***Correction for tool sensor errors, field variation and interference using near real-time data***

The effectiveness of multi-station corrections (➔ 5.2) which track tool sensor performance as well as external interference is greatly enhanced by the availability of real-time estimates of the magnetic field. Generally speaking, these methods have yet to be successfully automated, and their application remains the preserve of office-based staff within the directional drilling companies.

FREQUENCY OF DATA DELIVERY

The appropriate frequency of data delivery to the rig depends on operational requirements and is inevitably a compromise between:

- Keeping the rig appraised of the best estimate of the well position at all times
- Avoiding the proliferation of datasets with different processing applied
- Minimising operational cost

During times of relative magnetic calm, the field variations can be adequately monitored on a daily basis, and delivery of the updated wellbore position may be left to the end of each hole section. In periods of high magnetic disturbance, or when knowledge of wellbore position is critical, near real-time updates will be required to maintain survey performance within the pre-determined bounds. If the primary reason for applying IIFR is for future well collision avoidance, or for improved reservoir mapping, processing need not be undertaken until drilling is complete.

Monitoring magnetic variations daily and reacting to problems as they occur is a usually satisfactory compromise. This allows update to the wellbore position daily or at casing point dependent on circumstances.

SERVICE MANAGEMENT AND COMMUNICATIONS

Acquisition and delivery of IIFR data involves up to four organisations. The operator, the directional drilling company, the MWD survey company and the providers of the magnetic observatory data all play an important role. Rapid and robust verbal and digital data links are critical to success. Transmission of data either by hand-entry or fax is inadequate except as a temporary measure.

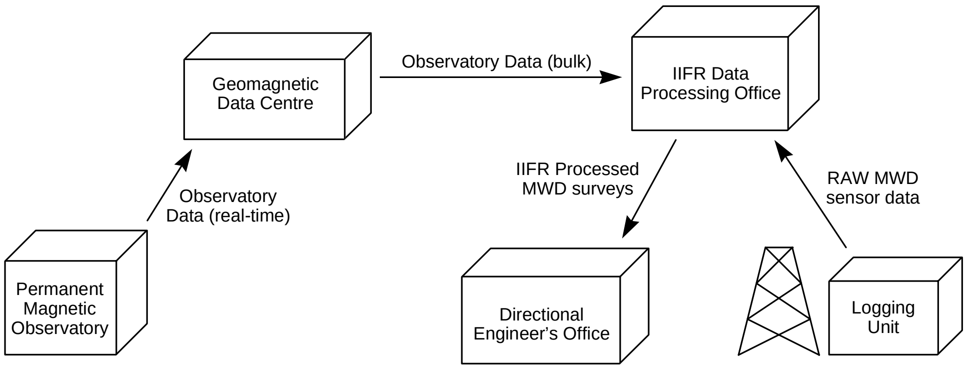


Figure 4.19

Typical data flow in an IIFR operation

OWNERSHIP AND PATENT RIGHTS

The concept of the 'virtual magnetic observatory' was developed by, and is patented jointly by Baroid Technologies (Sperry-Sun) and the UK Natural Environmental Research Council (British Geological Survey) under international patent WO9710413. When providing interpolated magnetic observatory data for this purpose, the BGS now levy an additional charge in respect of the use of this patent.

The patent does not cover the use of aeromagnetic data for the generation of anomaly maps, nor the taking of magnetic field measurements at the rig site. It is recommended that the precise in-field referencing service for a particular operation be determined with the advice of UTG.

4.9 Drill-String Magnetic Interference

Magnetic interference from the drill string is a potentially serious source of error for all magnetic survey tools. It has two components:

- **Axial interference** acts along the long axis of the BHA, and is usually much the stronger component. Simple interference corrections assume all drill-string interference is axial
- **Cross-axial interference** acts at right angles to the long axis of the BHA. It is difficult to correct for and acts as unwelcome 'noise' in simple corrections

Axial Interference

The basic theory of axial interference given here has been accepted and applied in the Industry for decades, and remains the basis for most calculations and corrections.

BASIC THEORY

Magnetic (ie non-non-magnetic) components in the BHA are assumed to act as bar magnets, with each end being a monopole. The field intensity, B_m, due to this monopole is a function of the pole strength, P, and it's distance, z:

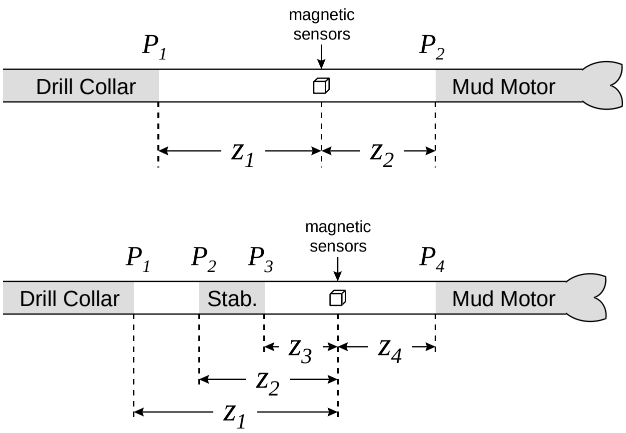
$$B_m = \frac{P}{4\pi z^2}$$

B_m is in micro-Tesla (=1000 nano-Tesla), z is in metres, and P has units of micro-Webers (μWb). A typical pole strength for a BHA component is 400μWb, and this can be used as a 1 s.d. value in the absence of more detailed information. It should certainly <u>not</u> be used as a maximum value.

The total axial interfering field, B_{ax}, may be estimated from the sum of the effects of all the monopoles in the BHA. Figure 4.20 shows how this works for two possible configurations. It is assumed that all fields are additive (worst case). Magnetic components are shaded, non-magnetic components are white.

Figure 4.20

Estimating magnetic axial interference



$$B_{ax} = \frac{1}{4\pi}\left(\frac{P_1}{z_1^2} + \frac{P_2}{z_2^2}\right)$$

$$B_{ax} = \frac{1}{4\pi}\left(\frac{P_1}{z_1^2} + \frac{P_2}{z_2^2} + \frac{P_3}{z_3^2} + \frac{P_4}{z_4^2}\right)$$

IMPACT ON BHA DESIGN

The azimuth error, Δ_{az}, caused by axial magnetic interference is a complex function of hole direction, tool orientation, the local magnetic field vector and the intensity of the interfering field. When the interfering field is much weaker than the horizontal component of the Earth's field, the following expression is a useful approximation:

$$\Delta_{az} = \frac{180}{\pi}.\frac{B_{ax}}{B_H}.\sin(Inc).\sin(Azi)$$

where B_H is the horizontal magnetic field strength (use table 3.2 for an approximate value), and Inc and Azi are the hole inclination and <u>magnetic</u> azimuth respectively.

In general, BHAs should be designed such that this estimated value of axial interference error is no greater than 0.5°. This will be a one standard deviation value if the magnetic pole strengths used in the calculation are estimated at 1 s.d.

AXIAL INTERFERENCE CORRECTIONS

Simple algorithms which attempt to correct for axial interference have been in use for many years. They are all based in some way on the principle illustrated in figure 4.21:

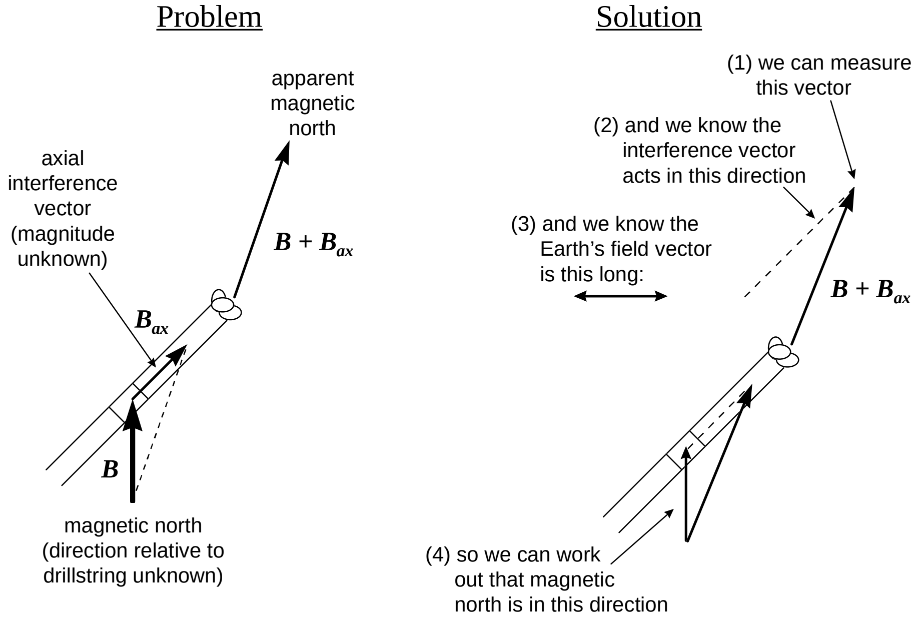


Figure 4.21

The principle of simple axial interference corrections

The above figure suggests the following limitations of these methods:

- They rely on an accurate knowledge of the local Earth's magnetic field. Where no direct observations are available (ie. unless in-field referencing is in use) and reliance is placed on a main field model, these corrections must be used with great care
- They rely on the absence of both cross-axial interference and external interference (➔ 4.9)
- No solution is possible if the geometry of the Earth's field vector and interference vectors is unfavourable. Unfortunately, this occurs precisely when the effect of axial interference is at its worst – when the well is both near horizontal and near magnetic east-west

- As a result of these limitations, the following precautions should be observed when using these methods:

- Corrections greater than those in the table below must not be accepted. They are indicative of survey errors greater than those predicted by the approved error models. Likely causes are (a) inaccurate magnetic field values (b) cross-axial or external magnetic interference

Table 4.4

Maximum acceptable axial magnetic interference corrections, by region

Drilling Area	Maximum Acceptable Correction
Gulf Coast, Middle East, Far East, Africa, South America, FSU	6°
North Sea, Northern Europe, Canada, Norway	8°
Alaska	10°

- Survey sensors must always be at least 4 m (13 ft) from magnetic drill string components. Within this distance, cross-axial interference is a real possibility.

- Axial magnetic interference corrections must never be used when the numerical value of sin(*Inc*)sin(*mag Azi*) exceeds 0.95. This translates into the following table of forbidden hole directions:

Table 4.5

Forbidden hole directions for axial magnetic interference corrections

Azimuth of Well	Forbidden Inclination Range
Magnetic E or W ± 19° or more	no restriction
Magnetic E or W ± 18°	87° – 93°
Magnetic E or W ± 15°	80° – 100°
Magnetic E or W ± 10°	75° – 105°
Magnetic E or W ± 5° or less	72° – 108°

In very high latitudes, it may be necessary to place further restrictions on the range of applicable hole angles.

MULTI-STATION DATA ANALYSIS

All the major directional drilling companies have now developed MWD data analysis methods which go beyond simple axial interference correction. These 'multi-station analyses' each require several MWD surveys as input. Best results are obtained when the data contains a wide variation in toolface angle. A rotation shot is ideal. The reduction in magnetic field uncertainty offered by in-field referencing allows the details of individual sensor performance to be distinguished.

The development and validation of INTEQ's method is described in **SPE 49060 Practical Application of a Mulitiple-Survey Magnetic Correction Algorithm**

Multi-station analyses are already in use for data validation and problem diagnosis, although the number of personnel proficient in their use is still limited. There is no doubt that these methods are also capable of improving overall MWD survey accuracy, but understanding of their performance is at an early stage. The associated BP Amoco approved error models (➔ B) therefore remain conservative.

4.10 Survey Data Comparison

Comparison of overlapping survey datasets is the most powerful and most revealing method of quality assurance available to the surveyor or engineer. Three methods are described here – T-plots, error ellipses, and a tabular method known as Relative Instrument Performance analysis (RIP).

Requirements of Comparison Methods

Survey data comparison is primarily a QA technique, designed to reveal significant differences between independent surveys. 'Significant' is here used in its statistical sense of 'not due to random variation'. Thus:

- The comparison method must be able to distinguish between statistically significant and random levels of disagreement between surveys

When a significant difference is identified, the next task is to try and determine its cause, and which instrument is at fault. Thus:

- The comparison method must give insights into the nature of any survey discrepancy, which will help identify its cause

None of the three methods presented here fulfil both these requirements completely, so it is often necessary to use more than one.

Survey T-Plots

T-plots are scatter diagrams showing the variation of hole direction with depth (invariably measured depth). They take their name from the traditional arrangement of the axes:

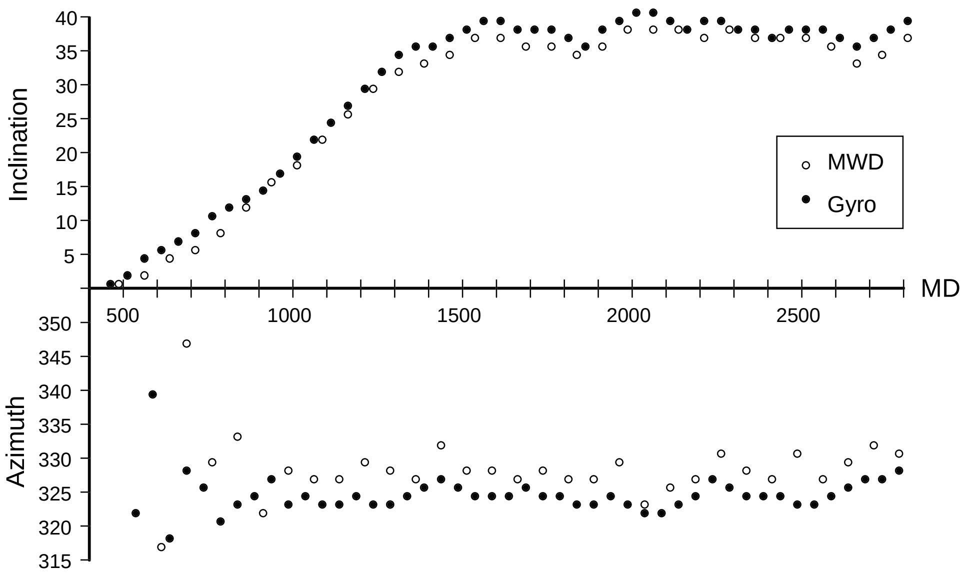


Figure 4.22

A Survey T-Plot

T-plots are the best way of displaying multiple survey datasets on a single sheet of paper. Systematic and random differences are immediately apparent, as are depth shifts. Trends which may indicate gyro drift or magnetic interference can also be distinguished.

The one attribute a T-plot must have is a **sufficiently large scale**. 1°/cm or 2°/in is ideal. For this reason, T-plots on A4 or 8½? x 11? paper are of little value – except to give unwary engineers a false impression of the data quality.

T-plots do not show whether the angular differences between surveys are larger than would be expected given typical tool performance. This requires one the following methods.

The Error Ellipse Method

Checking for the overlap of error ellipses is a simple and easily understood method of survey data comparison. Error ellipses, defined at one, one-and-a-half or two standard deviations, are plotted around the well positions as determined by two (or more) surveys. Whether or not the ellipses overlap is a semi-quantitative measure of the surveys' agreement.

For a valid comparison to be made, the ellipses should represent the uncertainty in the point at which the well intersects a particular plane. To compare horizontal position, the ellipses are plotted for a given TVD. For high angle and horizontal wells, it is better to plot the ellipses on a plane perpendicular to the well (the travelling cylinder plane).

➔ The equations for calculating these ellipses are in Section A.2

Four categories of agreement/disagreement may distinguished:

Overlap at 1 s.d.	*Good agreement.* No further investigation necessary.
Overlap at 1.5 s.d. but not at 1 s.d:	*Average agreement.* No further investigation necessary.
Overlap at 2 s.d. but not at 1.5 s.d	*Poor agreement.* Recheck both surveys carefully.
No overlap at 2 s.d.	*Disagreement.* One or other survey almost certainly contains a gross error. Investigate to resolve the discrepancy.

Table 4.6

Rules-of-thumb when using the error ellipse method

Unfortunately, the probability of each of these categories occurring is not constant for all pairs of surveys, so directly comparable pass/fail criteria cannot be defined. This is why the method is classed as 'semi-quantitative'. However, probabilities (or confidence levels) can be calculated if we make certain assumptions:

- The two surveys are completely independent (ie. no single error affects them both)
- The two error ellipses have the same shape
- The two error ellipses have the same orientation

With these assumptions, a table of probabilities can be drawn up. The table shows the probability that two survey tools, both performing within their approved error models, will produce non-overlapping ellipses. The smaller this probability, the greater the suspicion that one or both surveys contains a gross error. Note that the probabilities depend on the ratio of the sizes of the ellipses (ie. the ratio of tool accuracy) as well as on the number of standard deviations at which the ellipses are plotted.

Table 4.7

Quantitative interpretation of the error ellipse method

Probability that ellipses will not overlap	**1 s.d. ellipses**	**1.5 s.d. ellipses**	**2 s.d. ellipses**
Ratio (R) of ellipse sizes **R = 1**	37 %	11 %	2 %
R = 2	41 %	13 %	3 %
R = 3	45 %	16 %	4 %

Relative Instrument Performance Analysis

RIP analysis is a fully quantitative method of survey tool comparison. It determines the inclination or azimuth difference between two surveys and compares them with the difference to be expected from normal statistical error. The sequence of computation is as follows:

- Designate one survey (normally the more accurate) as the **reference survey** and the other as the **comparison survey**
- At each comparison survey station depth in the overlap interval:
  - Interpolate the reference survey inclination
  - Compute the **observed inclination difference** by subtracting the reference survey inclination from the comparison survey inclination
  - Compute the one standard deviation (1 s.d.) inclination uncertainty for the definitive and comparison surveys using approved error models
  - Compute the 1 s.d. inclination difference between the surveys from the root-sum-square of the inclination uncertainties
  - Divide the observed inclination difference by the 1 s.d. difference to give a **normalised inclination difference** (measured in standard deviations)
- Find the mean and standard deviation of all the normalised inclination differences in the overlap interval and interpret the results (see below)
- Repeat for azimuth differences

Table 4.8

Example of a Relative Instrument Performance analysis for azimuth differences

MD	Comparison survey azimuth		Interpolated reference survey azimuth		Observed azimuth difference	1 std.dev. azimuth difference	Normalised azimuth difference
(ft)	survey	1 s.d.	survey	1 s.d.			(std dev.)
	A	*B*	*C*	*D*	*E = A - C*	*F =* $\sqrt{B^2+C^2}$	*G = E / F*
1349	135.7°	0.78°	136.61°	0.35°	-0.91°	0.85°	-1.06
1444	136.4°	0.78°	137.54°	0.35°	-1.14°	0.85°	-1.33
1538	136.9°	0.79°	137.81°	0.36°	-0.91°	0.87°	-1.05
1632	137.2°	0.81°	138.45°	0.37°	-1.25°	0.89°	-1.40
1727	136.9°	0.82°	138.59°	0.37°	-1.69°	0.90°	-1.88
1822	137.7°	0.82°	139.02°	0.37°	-1.32°	0.90°	-1.47
1916	138.9°	0.83°	139.66°	0.38°	-0.76°	0.91°	-0.83
2011	138.1°	0.84°	140.45°	0.38°	-2.35°	0.92°	-2.55
2106	139.5°	0.84°	140.73°	0.38°	-1.23°	0.92°	-1.33
2200	141.6°	0.84°	141.75°	0.39°	-0.15°	0.93°	-0.16
2294	141.6°	0.85°	142.18°	0.40°	-0.58°	0.94°	-0.62
2388	142.7°	0.86°	142.89°	0.40°	-0.19°	0.95°	-0.20
						mean	**1.56 s.d.**
						std. dev.	**0.65 s.d.**

A large mean normalised error is indicative of a systematic error in one or both surveys. A large standard deviation is indicative of either large random errors, or a systemtic error which varies over the survey (eg. gyro drift or drillstring interference).

The following table, based on experience, will help interpret the results:

Normalised Difference (Incl. or Azim) Mean		Std. Dev.	Interpretation
< ± 0.5	**and**	< 0.5	*Good agreement*
± 0.5 to ± 0.75	**or**	0.5 to 1.0	*Average agreement*
± 0.75 to ± 1.25	**or**	1.0 to 1.5	*Poor agreement*. Re-check both surveys carefully
> 1.25	**or**	> 1.5	*Disagreement*. One or other survey almost certainly contains a gross error. Investigate to resolve the discrepancy.

Table 4.9

Rules-of-thumb for use with Relative Instrument Performance analyses

Section 5
Survey Tools

Contents

Section 5
Survey Tools

Contents (cont'd)

Section
5

Survey Tools

The surface and subsurface instrumentation used in wellbore surveying.

This section describes the applications and operating principles of the survey tools available for use today. Detailed specifications, diagrams and dimensional data are not given – these are available from the tool suppliers.

Brief descriptions of tools which are no longer in use, or are not recommended for use have also been included. Many old wells will incorporate the measurements of these tools in definitive surveys, and the engineer should know enough about them to be able to judge the likely quality of the data they produce.

Recommended Practices for tool selection and operation are in italics.

5.1 Inclination Only Tools

Inclination only tools are, as the name indicates, survey tools which measure only the hole inclination, and give no indication of hole azimuth. They are sometimes called **inclinometers** or **drift indicators**.

Applications

Inclination only survey tools have very limited application.

Their use should be restricted to near-surface sections of isolated exploration wells or well-spaced development wells.

A well-spaced development is one in which there is sufficient separation between wells to allow for the surface uncertainty, surface positioning tolerance and survey uncertainty and still leave sufficient room to drill safely.

The following table shows how the positional uncertainty associated with inclination only survey tools increases greatly if there is significant hole inclination.

Table 5.1

Position uncertainty for inclination only surveys

Average Measured Inclination	Position Uncertainty at 1.s.d. (ft/1000ft or m/1000m)
0°	13
0.5°	22
1°	31
1.5°	39
2°	48
2.5°	57
3°	65

There is nothing in the Drilling and Well Operations Policy to exclude inclination only surveys from use in definitive surveys, provided all the well's positioning objectives are met, and the well won't pose a collision risk to future drilling. Nevertheless,

Inclination only sections near surface should normally be resurveyed later in the drilling operation.

The usual requirements of data redundancy (➔ 4.2) will generally ensure this is the case.

Tool Descriptions

There are two essentially different types of inclination only tool in current use. The simple *TOTCO* so called after its original manufacturer, and the slightly more sophisticated Teledrift style of tool.

THE *TOTCO* INCLINOMETER

TOTCO style inclinometers are the most basic type of survey tool. The mechanism consists of a pendulum, with a stylus attached, and a disk of paper which the stylus penetrates when a survey is taken. The paper is marked with concentric rings indicating the hole inclination.

The instrument, enclosed in a protective barrel, is dropped down the drill string and lands on a baffle plate or '*TOTCO* ring' in the BHA. A mechanical timer is set on surface to ensure the survey s taken after the tool has landed. The tool may also be run on wireline.

THE *TELEDRIFT* INCLINOMETER

The *Teledrift* tool is an inclination only tool run by Scientific Drilling. It is in effect a simple MWD device, with a 'sensor unit' and pulser housed in a purpose-built sub. Andergauge market a very similar tool called the *Anderdrift*.

A pendulum in the tool is linked to a plunger, which passes through a number of restrictions, the number depending on the hole inclination. Each restriction is detected as a mud pulse by a surface system, allowing the inclination to be calculated. The tool has a range of 2.5° in half degree increments. The range, which can be chosen anywhere between 0°-2.5° and 7.5°-10°, is pre-set on surface. Inclination readings are triggered by cycling the pumps.

Despite their apparent simplicity, these tools have suffered reliability problems in the past and are now little used.

5.2 Measurement While Drilling (MWD)

Applications

The large majority of BHAs run in BP Amoco wells include an MWD tool. They are used for surveying the well as drilling proceeds and may also acquire formation evaluation data and measure drilling parameters. There are two situations where BHAs are commonly run without MWD tools:

- Vertical hole sections in isolated wells. Formation evaluation MWD (FEWD) tools will frequently be required through the reservoir section of vertical exploration wells, either instead of or in addition to wireline logs

- Drilling in close proximity to other wells when external magnetic interference is likely to affect an entire hole section. In this case, survey and toolface data will be provided by gyroscopic single shots. If magnetic interference is only expected to persist for part of a hole section, an MWD tool is usually included in the BHA from the start. This allows the time-consuming gyro single shot surveys to be dispensed with at the earliest possible moment

Tool Descriptions

MWD tools are mounted inside non-magnetic drill collars, as close behind the bit (and motor if present) as possible, within the constraints of non-magnetic spacing (➔ 4.9). There is a huge variety of tools and arrangements suitable for different applications.

In **collar-mounted** tools, the sensors and electronics are built directly into the body of a specially manufactured drill collar. This allows a clear ID through which lost circulation material may be pumped. Power is usually provided by a mud turbine. Due to space requirements, collar-mounted tools can only be used in 8-1/2" and larger hole sizes. **Probe-type** tools are mounted in protective barrels and sit in the ID of a standard non-magnetic drill collar, although the pulser unit (see below) may be mounted in its own sub. Probe-type tools are typically battery powered and are available for use in all hole sizes down to 4-3/4".

DATA TRANSMITTAL

In the vast majority of MWD systems, data is transmitted from the tool to surface via **mud-pulse telemetry** – encoded pressure changes in the mud inside the drill string. The pressure changes at the stand pipe are automatically read and decoded into tool measurements at surface. There are three types of mud-pulse telemetry: **Positive pulse**, in which momentary restrictions in the drill string ID create peaks in the pressure trace; **negative pulse**, in which a small amount of mud is vented to the annulus, creating troughs in the pressure trace; and **continuous wave** telemetry, in which the pressure is modulated by a rotor/stator combination. Anadrill are the only MWD company to use continuous wave telemetry.

The alternative to mud-pulse telemetry is **electromagnetic telemetry**. A varying voltage across the MWD creates an electromagnetic wave which is detected by a receiver in the ground (or sea bed). Data rates are slower than with mud-pulse telemetry, but transmission is possible while making a connection. Electromagnetic telemetry has a niche application when drilling with compressible fluids such as foam or air which cannot sustain a pressure pulse.

Because of limited data transmittal rates, not all MWD measurements are transmitted in real-time to surface. High volume data such as BHA vibration and some formation evaluation measurements are often stored downhole in memory modules. The data is recovered when the tool is returned to surface.

DIRECTIONAL SENSORS

All magnetic MWD, electronic multishot and steering tools work on the same principles. Each has a sensor package consisting of three **accelerometers**, each of which measures the component of the Earth's gravity field along it's principal axis, and three **magnetometers** which do the same for the Earth's magnetic field.

The three accelerometers are mutually perpendicular, with one pointing along the tool axis, and two at right angles to it. The magnetometers are arranged in exactly the same way.

Tool Operation

Surveys are normally taken when the tool is stationary and the pumps are off. The data is transmitted to surface when the pumps are turned back on. In some tools, inclination, azimuth and toolface updates are available while drilling. These are particularly useful when kicking-off or side-tracking.

TOOLFACE MEASUREMENT

When a directional BHA is in use, the directional driller is interested in the rotation angle of the bend (up, down, left, right). This is known as the **toolface angle**. The rotation angle measured by the MWD is referenced to the tool sensor directions (figure 5.1), not the bend in the BHA. The offset between the two directions must be measured at surface when the BHA is made up, and added by the MWD surface software before being displayed to the driller.

The determination of this offset is a safety-critical task, and must be checked independently before the BHA is run in hole.

When kicking off from vertical, the BHA is oriented in the desired direction using the MWD as a compass. The azimuth at which the bend of the BHA is pointing is called the **magnetic toolface**.

Once the MWD tool has reached a certain minimum inclination (typically 3° or 5°) the direction of the BHA bend is measured with respect to the hole angle (up=0°, down=180°, left=270°, right=90°,), using the accelerometers alone. This measurement is called **gravity toolface** or **highside toolface** and is used by the directional driller for further steering. It has the advantage of being unaffected by magnetic interference.

‘RAW’ VS. COMPUTED DATA

Most MWD tools can be configured to transmit the six individual sensor measurements to surface, rather than just the inclination, azimuth and toolface. This will take a little longer, but is vital if more than basic quality assurance is to be attempted.

Six-sensor ‘raw’ data should normally be transmitted to surface, with inclination, azimuth and toolface (and associated QA measures) being calculated from it.

Quality Assurance and Data Validation

All MWD surveys must pass a number of internal and external validation checks. Details are below and in JORPs.

INTERNAL QUALITY ASSURANCE

The standard ‘self-check’ on MWD surveys is the computation from the sensor data of three physical quantities:

- G-total – the gravity field intensity.
- B-total – the magnetic field intensity

- Dip angle – the angle the magnetic field vector makes with the horizontal

➔ Section A.3 contains details of how to calculate these quantities

Deviations of more than a few percent from known or theoretical values indicate tool error, tool movement, or magnetic interference.

The values of B-total and dip angle are affected by magnetic interference. Inadequate magnetic isolation of the MWD and reliance on an axial interference correction will invalidate the internal QA (➔ 4.9).

EXTERNAL DATA VALIDATION

Except in the special circumstances detailed below, internal QA is not sufficient to guarantee the accuracy of the survey data. Therefore

Each MWD tool must pass a comparison with external data.

This may be achieved in three ways:

CHECK SHOTS

Every time a new BHA is run in hole, a rotation shot (4 MWD surveys) is taken at some fixed depth beyond the zone of magnetic interference from the casing shoe. It is best to use the same depth for all BHAs in the hole section, but this may be varied, if necessary, to prevent localised wash-out. All the calculated check shots should agree within the following limits:

Maximum spread in inclination:	0.5°
Maximum spread in azimuth:	3.0°

Results outside these limits will require the rotation shot to be repeated. A confirmed discrepancy will require the tool to be changed out.

If the same MWD/BHA is used on successive bit runs, the maximum differences between check shots are halved, viz:

Maximum spread in inclination:	0.25°
Maximum spread in azimuth:	1.5°

In addition to the rotation shot below the casing shoe, the deepest survey taken with the previous MWD should be repeated with the new tool to ensure repeatability of results. Allowable discrepancies and consequences of failure are the same as for rotation shots.

Whenever possible, MWD tools should be changed out during bit trips.

This helps eliminate the possibility of a systematic error going undetected, and adds confidence to the MWD results should a discrepancy with another survey tool arise.

ELECTRONIC MULTISHOT

If a hole section is completed in a single bit run, external data validation may be completed by running an electronic magnetic multishot survey (EMS) prior to tripping. Whenever there is a possibility that section TD may be reached with the first BHA, a *TOTCO* ring and possibly additional non-magnetic collars above the MWD should be included in the BHA as a contingency against the need to run an EMS.

MULTI-STATION DATA ANALYSIS

When in-field referenced estimates of the local magnetic field are available (➔ 4.7) and are used as inputs into a multi-station data analysis (➔ 4.9), there is no further requirement for external data validation. Experience with multi-station analyses has shown them capable of detecting (and sometimes correcting) a wide variety of errors to which MWD tools are prone.

DISPENSATION FROM EXTERNAL VALIDATION

External validation of MWD data will not be required if either:

- The entire MWD run is below 5° inclination and there is no associated anti-collision risk, **or**
- The MWD run is a short section at the end of the well with no significant change in hole direction, and again, there is no associated anti-collision risk

MAGNETIC DISTURBANCE MONITORING

Every company providing magnetic survey services, including MWD, should have access to magnetic disturbance predictions and real-time activity reports and should have some form of alert system to indicate when the survey service is liable to disruption. Several internet sites have detailed magnetic activity forecasts and reports.

MWD Accuracy Enhancement

A number of techniques have been developed to increase the accuracy of MWD measurements. Amongst these are in-field referencing (➔ 4.7), in-hole referencing (➔ 4.8) and magnetic interference corrections (➔ 4.9)

All these methods only impact azimuth accuracy. Inclination accuracy can be improved by application of **BHA sag corrections**. These work by modelling the BHA as a stiff cantilever, supported by the hole wall at the bit and stabilisers, and free to deform under gravity between these supports. Sag corrections of widely differing complexity are available, ranging from simple beam models to full finite element analyses. The BP Amoco approved error models (➔ B) do not differentiate between them.

5.3 Electronic Magnetic Multishots

Electronic magnetic multishots (EMS) are solid state survey tools. They are the direct successors to camera-based magnetic multishots (➔ 5.5).

Applications

EMS surveys are usually taken at or near section TD. Where the section has been surveyed with magnetic single shots, the EMS will provide a definitive survey. Where MWD has been used, the EMS will not greatly improve accuracy, and it's principal purpose will be for survey validation, although it may also be selected as the definitive survey. EMS tools are also used for orienting cores.

Most EMS tools will record over 1000 survey stations – enough for any open hole section. Some tools, known as **Electronic Single Shots** (ESS) have a restricted memory capacity of only a few stations. This is still adequate for MWD data validation.

Tool Description

EMS tools are housed in barrels ranging from 1.0" to 2.0" OD. They are usually centralised in the drill string by means of rubber fingers at top and bottom. To reduce the risk of an unsuccessful survey and a costly re-run,

two probes should be run in tandem for all EMS surveys.

EMS sensors have the same configuration as MWD tools, with three accelerometers and three magnetometers. Some survey companies use identical sensor packages (manufactured by the electronics company AlliedSignal, formerly Tensor) in both tool types.

Tool Operation

The tool is made up on surface and a time delay set so it will start taking surveys at a predetermined time. It is dropped down the drill string prior to a trip. In high angle hole, the tool may be gently pumped to bottom.

The tool lands on a baffle plate (sometimes called a '*TOTCO* ring') in the BHA. As the drill string is tripped out of hole, the survey engineer keeps a tally of bit depth against time, which will later be used to assign a measured depth to each timed survey.

When the tool is recovered at surface, it is plugged into the engineer's surface computer, which reads the tool's memory and computes the survey.

NON-MAGNETIC SPACING

➔ MWD non-magnetic spacing requirements are in Section 4.9

There must be sufficient non-magnetic material above the *TOTCO* ring to allow adequate magnetic spacing for both probes.

Non-magnetic spacing requirements for electronic multishots are the same as for MWD, with the additional requirement that neither sensor be within 1.5 m (5 ft) of a tool joint.

ROTATION SHOTS

Up to three sets of rotation shots are usually taken during an EMS survey. These are sequences of 8-10 surveys between which the drill string is rotated, but not moved up or down, which provides a set of surveys at the same depth but with a range of toolfaces. The results can be used to correct for tool and sensor misalignment. Rotation shot practices vary slightly between survey companies – their JORPs documents have details (➔ 5.10).

Quality Assurance

Many of the same QA measures that are applied to MWD are also applied to EMS surveys. The following table has details:

QA measure	Tolerance	Failure indicates	Possible cause(s) of failure
Divergence between probes – Lateral	< 5/1000	Systematic azimuth error	magnetic interference
Divergence between probes – TVD	< 2/1000	Systematic inclination error	tool misalignment or BHA sag
Gravity Field Strength (G-total)	< ±0.007g* (all surveys)	Inclination and azimuth error	Faulty accelerometer or tool movement
Magnetic Field Strength (B-total)	< ±700 nT* (all surveys)	azimuth error	magnetic interference, large crustal anomaly
Magnetic Dip Angle	< ±0.7°* (all surveys)	azimuth error	magnetic interference, large crustal anomaly

* difference from modelled value

Table 5.2

Quality measures for electronic magnetic multishot surveys (generic)

5.4 North-Seeking and Inertial Gyros

North seeking gyroscopes, also called 'rate gyros', align themselves with True North by sensing the rotation of the Earth. Any rotational torque applied to a spinning mass gyroscope will cause a reactive torque around a perpendicular axis. When a north-seeking gyro tool is held stationary in a well, the rotation of the Earth is sensed as a torque. The magnitude of this torque is a measure of the alignment of the gyro spin axis with True North.

In fact, only the horizontal component of the Earth's spin vector is of use in determining True North. This has magnitude:

$$\text{Horizontal Earth Rate} = \Omega_H = 15.041 \cos(\mathit{Latitude}) \text{ deg/hr}$$

The dependency on latitude means that the accuracy of all north-seeking gyros diminishes near the Earth's geographic poles.

Gyrodata North-Seeking Gyro Tools

Gyrodata's *Wellbore Surveyor* (*GWS*) is their original north-seeking gyro. It must be stationary to take a survey and becomes rapidly less accurate at greater than 70° to 75° inclination. Two developments of the tool have extended its utility and range of application. The *Battery/Memory* tool (*RGS-BT*) has an internal power supply and survey storage capacity which enable it to run isolated from surface systems. The Continuous tool (*RGS-CT*) can survey on-the-move above 15° inclination and remains accurate at all hole angles.

APPLICATIONS

The main applications of the *Wellbore Surveyor* are now:

- Single shot orientation surveys
- Wellhead orientations

The tool may also be run in combination with other wireline logging tools.

Because of improved running speed and accuracy, the *Continuous* tool is preferred for:

- Casing/tubing multishot surveys
- Drill-pipe multishot surveys

The *Battery/Memory* tool extends this range further:

- Slick line multishot surveys
- Drop multishots (the tool is dropped down the drill string and the survey taken while tripping out)

TOOL DESCRIPTION

Tool dimensions depend on running gear configuration and application. Typical length is 6 m (20 ft). Tool OD ranges from 2.25" to 3.6" depending on the type of pressure barrel or heatshield used. A small diameter gyro tool with an OD of 1.75" is also available.

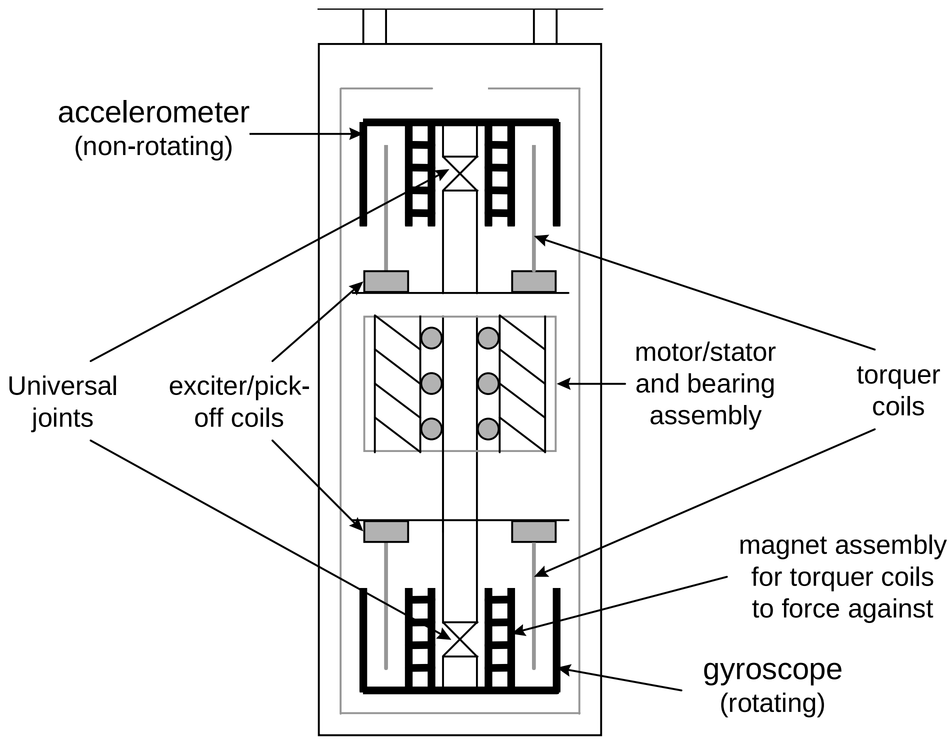


Figure 5.1

Sensor arrangement in Gyrodata's Wellbore Surveyor (large diameter tool)

The sensor assembly of the large diameter tool consists of a 2-axis gyroscope and a 2-axis accelerometer. These are physically similar – it is the spinning of the gyro which gives them their separate functions.

The small diameter tool uses two or three single axis accelerometers.

In the *Wellbore Surveyor* and *Battery/Memory* tools, the gyro is used for north-seeking (ie. azimuth determination) while the accelerometer measures inclination. In the *Continuous* tool (above 15° inclination) the gyro measures changes in both inclination and azimuth with respect to the initial alignment.

OPERATIONAL SEQUENCE – CONTINUOUS MULTISHOT SURVEY

Where possible (ie. on land rigs and some fixed structures), pre-job and post-job roll tests are performed with the tool on the deck to confirm tool calibration.

From surface until an inclination of 10°-15° is reached, surveys must be taken with the tool stationary. This is called **gyrocompassing**. At some point between 10°-15° inclination, the tool inclination, azimuth and orientation are initialised before switching to continuous mode. The tool is then run to TD, stopping every 30 minutes to check the drift. The outrun survey follows the same sequence in reverse. Re-initialising at 10°-15° inclination on the outrun effectively provides two independent surveys.

Field results are available at the rig site and the final survey is computed once the tool has been returned to base and has completed a 'field return map'. This is effectively a definitive calibration check for the survey.

OPERATIONAL SEQUENCE – DROP SURVEY

When used as a drop tool, the *Battery/Memory* tool is operated in exactly the same way as an electronic multishot (except it does not require to be landed in non-magnetic drill collars).

The tool takes gyrocompass surveys when the it is stationary (when the drill string is hung off in the slips) and records the results against an internal clock. The survey engineer keeps a time/depth tally while the drill string is tripped, and reconciles this with the survey once the tool is retrieved. All QA measures normally transmitted through the wireline in real time are recorded by the tool for later examination by the engineer.

QUALITY ASSURANCE

The following quality measures are acquired at the rig site:

QA measure	Tolerance	Failure may indicate	Possible cause(s) of failure
Field roll tests – mass unbalance (if possible)	< 0.4°/hr	poor initial azimuth reference	gyro calibration shift
Field roll tests – accel. scale factor (if possible)	< 0.00015	systematic inclination error	accelerometer calibration shift
In/Outrun comparison – inclination	Csg: mn, sd<0.3° D/P: mn, sd<0.3°	inclination error	depth error or running gear.
In/Outrun comparison – azimuth	Csg: m, sd<0.5° D/P: m, sd<0.75°	azimuth error	depth error or poor gyro performance
Final zero depth	< 2.0/1000	systematic error, primarily inclination	wireline slippage or stretch – correct to CCL
Wireline stretch at TD	< 1.5/1000	systematic error, primarily inclination	tool lag on inrun – correct to CCL

Table 5.3

Quality measures common to all Gyrodata surveys

Table 5.4

Quality measures for Gyrodata gyrocompassing surveys

QA measure	Tolerance	Failure may indicate	Possible cause(s) of failure
Single station test – Earth rate	< f_1(*Inc*,*Azi*)°/hr*	poor initial azimuth reference	noisy data – reinitialise deeper
Single station test – gyro drift & noise	mean<400 bits s.d.<400 bits	poor initial azimuth reference	noisy data – reinitialise deeper
Single station test – accel. drift & noise	mean<50 bits s.d.<50 bits	azimuth error	poor gyro performance or tool movement

* $f_1(Inc,Azi) = 1/\{\cos Inc\sqrt{[(0.1°\sin Inc.\sin Azi)^2+(0.08°)^2]}\}$

Table 5.5

Quality measures for Gyrodata continuous surveys

QA measure	Tolerance	Failure may indicate	Possible cause(s) of failure
Initialisation - inclination	s.d. *Inc* < 0.1°	Tool movement or calibration shift during tool make-up	knock during tool make-up
Initialisation - azimuth	s.d. *Azi* < 0.2°	tool movement or calibration shift during tool make-up	knock during tool make-up
Initialisation - Earth rate	< f_2(*Inc*,*Azi*)°/hr*	Tool movement or calibration shift during tool make-up	knock during tool make-up
Drift tune – X gyro	<0.2°, all params	invalid survey	poor gyro performance
Drift tune – Y gyro	<0.2°, all params	invalid survey	poor gyro performance

* $f_2(Inc,Azi) = 1/\{\cos Inc\sqrt{[(0.1°\sin Inc.\sin Azi)^2+(0.08°)^2/6]}\}$

Scientific Drilling *Keeper*

The *Keeper* has largely replaced the *Finder* as Scientific Drilling's multi-purpose gyro survey tool.

APPLICATIONS

The Keeper may be configured so as to fulfil a wide variety of applications:

- Casing/tubing multishot surveys
- Drill-pipe multishot surveys
- Single shot orientation surveys. Where rig motion precludes north-seeking, the tool can be optically referenced at surface, like a traditional surface read-out gyro (but with improved gyro and accelerometer performance)
- Slick-line multishot surveys (results are stored in the tool's memory)

The tool is robust enough to be used in 'gyro while drilling' and steering applications if required.

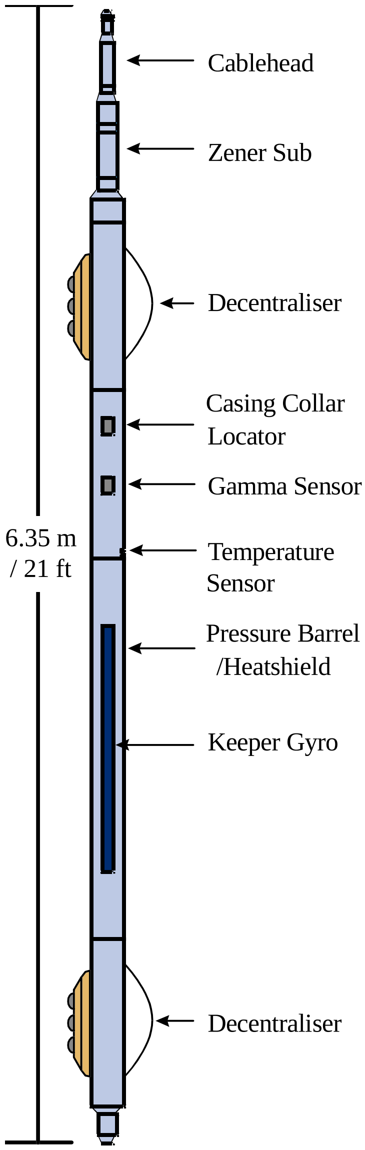


Figure 5.2

Keeper tool configured for a 9-5/8" or 7" casing survey

TOOL DESCRIPTION

The dimensions of the Keeper depend on the application. Typical lengths are 5 m (16 ft) for drill-pipe and orientation surveys, and 5-10 m (16-33 ft) for casing surveys, depending on whether a sinker-bar is required. Tool OD for casing surveys is 3", and for drill-pipe surveys 1.75"/1.85"/2.125" depending on whether a heatshield is required.

The tool has two orthogonal spinning mass gyros (X and Z) and two accelerometers (X and Y). The X gyro is used for initial north-seeking when the tool is vertical and for measuring azimuth changes above 20° inclination. The Z gyro is used for measuring tool orientation and azimuth changes between vertical and 20° inclination.

OPERATIONAL SEQUENCE – MULTISHOT SURVEY

Where conditions permit (ie. on land and some fixed installations), a field calibration is performed with the tool on the deck. Initialisation (north-seeking) can be performed at between 0° and 3° inclination – typically a compromise between tool movement near surface and decreased accuracy away from vertical. In casing surveys, a lock-arm can be used to eliminate tool movement.

A 2 minute ‘drift tune’ is performed to check gyro performance. The tool is then run continuous in ‘low angle high speed mode’ to 20° inclination, where another drift tune is taken. The tool then runs continuously to TD in ‘high angle high speed mode’, being stopped after every 15 minutes or 15° of angle change to measure drift and gyro bias.

At survey TD, the wireline stretch is removed by monitoring tool movement and allowing for the amount slack pulled in (the measuring head is not physically disengaged).

The outrun is a reverse of the inrun, except that the survey may be continued all the way to surface. If necessary, the interval from surface to the initialisation depth can be repeated to complete the ‘inrun’.

Where possible, a post-job field calibration will be performed after rigging down the tool.

OPERATIONAL SEQUENCE – SINGLE SHOT SURVEY

Field calibration, performed once per job, is as for multishot surveys.

The angle of the orienting stinger relative to the tool zero reference is measured and rechecked carefully at surface. North-seeking initialisation is again performed near vertical (<3°). The tool is then run into hole and seated carefully in the orienting sub before taking the final survey.

A check survey is taken at a pre-determined depth on the inrun and outrun to confirm the tool's repeatability and agreement with other tools. As a precaution against systematic errors, tools are changed out every 3 or 4 surveys.

QUALITY ASSURANCE

The following quality measures are acquired at the rigsite:

QA measure	Tolerance	Failure may indicate	Possible cause(s) of failure
Field calibration – mass unbalance	DI < 0.6°/hr DS < 1.0°/hr	poor initial azimuth reference	gyro calibration shift
Field calibration – accel. scale factor	< 0.0033 v/g	systematic inclination error	accelerometer calibration shift
Initialisation – gyro bias uncertainty	< 0.017°/hr	poor initial azimuth reference	noisy data – reinitialise deeper
Initialisation – Earth rate horizontal	< 0.07°/hr	poor initial azimuth reference	noisy data – reinitialise deeper
Low angle Mode – average G bias	< 0.8°/hr	azimuth error	poor gyro performance or tool movement
High angle Mode – average G bias	< 0.15°/hr	azimuth error	poor gyro performance or tool movement
Final zero depth	< 1/1000	systematic error, primarily inclination	wireline slippage or stretch – correct to CCL
Wireline stretch at TD	< 1.5/1000	systematic error, primarily inclination	tool lag on inrun – correct to CCL
In/Outrun comparison – inclination	Csg: sd<0.2° D/P: sd<0.4°	inclination error	depth error or running gear.
In/Outrun comparison – azimuth	Csg: sd<0.5° D/P: sd<0.75°	azimuth error	depth error or poor gyro performance

Table 5.6

Quality measures for Keeper multishot surveys

Baker Hughes INTEQ *RIGS*

RIGS stands for Ring-Laser Inertial Guidance system. It is widely acknowledged as the most accurate survey tool currently in service.

APPLICATIONS

Because of its size, use of RIGS is primarily restricted to casing and liner surveys (6.1" minimum ID). The tool is run on electric wireline, and all surveys are recorded from surface. Down-hole tie-ins are neither necessary nor recommended. The tool may also be used for wellhead orientation.

The internal electronics have a temperature limitation of 100°C. An external (mud) temperature of 150°C can be withstood for approximately 1 hr. or 200°C for 6 hrs. using a heatshield barrel (not suitable for 7" liner or smaller)

Maximum hole inclination is limited by friction in the well. The tool will typically 'hang-up' between 70° and 80°, depending on hole conditions. A tractor device to take the tool to horizontal is now available.

An additional sensor package of CCL, gamma and temperature can be run, forming the so-called 'RIGS+' system. This enables RIGS to be made the primary log in the well, allowing all other depth determined data to be correlated with the RIGS high accuracy positional data. This has benefits for subsequent, deeper surveys, petrophysical log data, packer setting, perforating, and other operations.

TOOL DESCRIPTION

The RIGS tool has a barrel OD of 5.25" and a dry weight of 180kg (400lb). Use of a heatshield increases these values to 5.875" and 225kg (500lb) respectively. Sinker bars, weighing up to 395kg (870lb) may be used to help the tool descend in high angle hole.

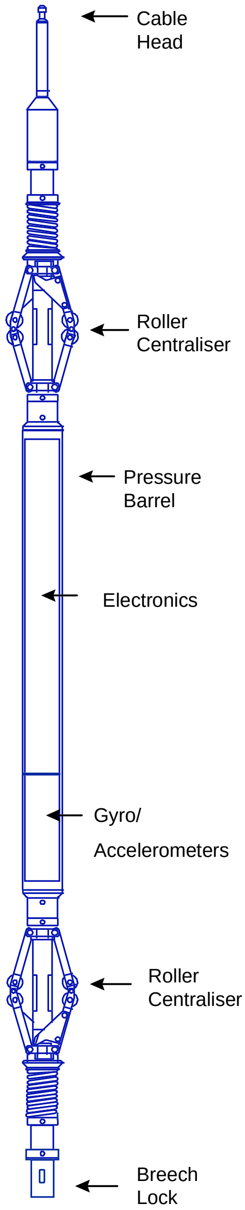


Figure 5.3

The RIGS survey probe

The Inertial Measurement Unit (IMU) comprises three solid state ring laser gyros, and three inertial grade accelerometers. The IMU outputs, and the wireline velocity, are inputs to the inertial navigation program. The program provides a continuous real-time output of measured depth, inclination, azimuth, toolface as well as North, East and TVD co-ordinates. Unlike the obsolete FINDS tool, RIGS is not a stand-alone inertial navigation system – it's navigation equations rely on accurate real-time wireline depth measurement.

OPERATIONAL SEQUENCE

RIGS uses Earth rotation to sense the direction of True north, just like other north seeking gyros. This alignment process requires the tool to be stationary for between 6 and 12 minutes before starting the inrun survey (depending on latitude).

Maximum running speed is typically 6400m/hr (21000ft/hr), but this may be severely reduced at high inclinations or by wireline limitations. Drift checks of three minutes duration are taken immediately after the initial alignment, at TD, and on completion of the outrun. These are checks are used for QC purposes only, they are not applied as corrections. The final computed survey is available immediately on completion of the outrun – no offline processing is necessary or possible.

QUALITY ASSURANCE

No rig site calibration of the tool is required. Calibration parameters are checked on the tool's return to base as a precautionary measure.

The following quality measures are acquired at the rig site:

Table 5.7

Quality measures for RIGS surveys

QA measure	Tolerance	Failure indicates	Possible cause(s) of failure
Alignment summary	< 0.1°	Noisy Alignment	Excessive 'electrical' noise Tool movement.
Drift checks	< 0.08 ft/min	Tool movement, or invalid survey.	Poor Alignment (1st check) Lost heading. Sensor failure. Tool movement.
In/Outrun comparison	within tool-defined ellipses of uncertainty	Out of spec performance at some stage in complete inrun/outrun survey. QC flow chart will indicate whether sufficient QC parameters exist to qualify survey as within specification.	Depth error. Sensor failure. Lost heading.

5.5 Camera-Based Magnetic Tools

Camera-based magnetic tools were the electro-mechanical forerunners of 'solid state' MWD and electronic multishot tools. They are also referred to as **photo-mechanical** magnetic tools.

Applications

Camera-based magnetic survey tools have a number of important disadvantages in comparison with solid state tools:

- Being analogue tools, rather than digital, they provide less measurement resolution, less quality assurance, and less scope for re-processing of results
- They are affected by, but give no indication of, internal or external magnetic interference
- They are unreliable at elevated temperatures

In many areas, these disadvantages have made the tools obsolete. Camera-based single shots may be used in vertical, isolated wells, for monitoring hole direction in mid-section. Survey requirements for relief well contingency (➔ 4.2) will usually dictate that the section be re-surveyed. Electronic multishots are recommended for this, although dipmeters may be used as an alternative.

Camera-based magnetic multishots are not a recommended tool type.

An exception might be argued for short, low-angle, near surface hole sections in isolated wells, especially if they are eventually to re-surveyed with a gyroscopic tool.

Tool Descriptions

The two styles of tool – single shot and multishot, work on the same principles and have the same key components:

- An angle unit, or compass unit, houses a combined pendulum and magnetic compass. Angle units with many different ranges are available.

  It is strongly recommended that only units ranges between 0-10° and 0-24° be used.

Smaller ranges can mislead the surveyor into underestimating the hole inclination, and the units are prone to vibration. Larger ranges do not provide adequate resolution, and should in any case not be required

- A camera, which takes a picture or pictures of the angle unit, indicating the hole inclination and azimuth. The film is developed and read on surface by the surveyor
- A mechanism for triggering the camera to flash. This may be a spring-driven or electric timer, a motion sensor, or, for single shots, a sensor which detects when the tool has entered the non-magnetic collars

Tool Operation

Both single shots and multishots are dropped from surface and landed in the BHA. There must be sufficient non-magnetic collars to isolate the tool from magnetic interference. Spacing requirements are the same as for MWD (➔ 4.9). If landed in an orienting muleshoe, the survey will give toolface as well as hole direction. Tools may be retrieved at surface when tripping, or by overshot and wireline.

Quality Assurance

Single shots should be run in tandem, to provide survey validation and protection against tool failure. Little further QA is possible given the analogue nature of the measurements.

5.6 Surface Read-Out Gyros

Strictly speaking, any gyroscopic survey tool which sends results to surface via wireline is a surface read-out gyro, but the name, sometimes abbreviated to SRG, is here applied only to optically referenced tools. Unlike north-seeking gyros, optically-referenced survey tools have no independent direction finding capability. The survey engineer must visually

align the tool with a fixed direction at surface. The tool then measures changes in hole direction, which are converted to azimuths by referencing to the known initial tool direction.

Applications

Because of the scope for human error, especially in surface referencing, surface read-out gyros have been largely superseded by north-seeking tools. Their remaining application is for near-surface single shots and BHA orientation, where external magnetic interference precludes the use of a magnetic tool. They may be more reliable than north-seeking gyros where rig motion causes excessive down-hole vibration.

SRGs must not be used:

- *For multishot surveys*
- *Deeper than 450m/1500ft below rotary table*
- *In hole inclinations greater than 10°*

These restrictions reflect the limitations in the performance of the tools, particularly their drift characteristics.

Tool Description and Operation

Surface read-out gyros are supplied by Scientific Drilling (‘SRG’), Baker Hughes INTEQ (‘Sigma’) and Sperry-Sun (‘SRO’).

Due to its historically poor performance, use of the Sperry-Sun SRO tool is not recommended.

The gyroscope, accelerometers and electronics are encased in a probe-type pressure barrel. After optical alignment at surface, the tool is run into the well on electric wireline. A mule shoe assembly at the bottom of the tool orients it in a UBHO sub within the BHA. A surface system set up near the drill-floor provides real-time orientation data.

The tool is retrieved on wireline and optically referenced again at surface. This allows a drift correction to be computed and applied.

SURFACE REFERENCING AND DRIFT CORRECTION

Serious errors with potentially disastrous consequences can and do occur as a result of mistakes made when referencing these tools at surface, and when computing and applying the drift correction. As a result,

Surface references must be established and checked by a qualified land surveyor, and recorded with a detailed station description. The survey engineer on the rig must have a copy of this station description.

Drift corrections must be computed and applied automatically by software. Reliance on hand computations by the survey engineer is not acceptable.

5.7 Dipmeters

'Dipmeter' is used here to describe the directional survey package incorporated in any wireline log. It thus covers the survey measurements acquired with such specific tools as the Schlumberger **OBDT** and **BGT**.

Applications

Dipmeters are not primarily surveying tools, and are not run by survey engineers. This inevitably affects the level of assurance of the data they produce. As a result, they should only be included in survey programmes after specific data processing and delivery procedures have been agreed with the vendor. The typical application of dipmeters as survey tools is as an alternative to an electronic multishot survey in vertical and low-angle wells, where MWD tools have not been used.

Tool Description and Operation

The directional sensors within wireline logging tools are typically of a similar quality to those found in dedicated survey tools. However, the running gear is not physically configured for survey accuracy, with often only a single contact point with the borehole wall. This leaves ample scope for tool misalignment.

Dipmeters are run in open hole on wireline, usually at the end of a hole section. The directional survey data will usually have to be requested specially from the logging contractor.

Quality Assurance

More than with other survey tools, there is often a significant gap between the data quality of which dipmeters are capable, and the quality that is eventually delivered. This is because survey data is usually perceived as secondary to the formation evaluation data in importance, and the tool is not run, nor the results processed, by qualified surveyors. For this reason, a few simple precautions should always be followed:

Make sure a hard copy of the data is provided, with sufficient header data to ensure its traceability.

Insist on all data being labelled with the azimuth reference (magnetic, grid or true) and the correction, if any, applied.

Visually inspect the survey for spurious data points, often indicated by large dog-leg severities.

5.8 Obsolete and Seldom Used Tools

Many BP Amoco wells were surveyed with survey tools which are now obsolete or have very restricted use. Each of these tools has a BP Amoco approved error model. Some insight into the likely quality of the data can be gained from the following brief descriptions.

Schlumberger *GCT*

An accurate and reliable north-seeking gyro tool, progressively decommissioned in the mid 1990's. Survey results were acquired, and often presented, with a very small station interval resulting in excessively long files. These can be interpolated at a more reasonable depth interval without appreciable loss of accuracy.

Sperry-Sun *G2*

A north-seeking gyro tool, still in occasional use. It runs continuously (with periodic stops for drift checking), but not as fast as the more modern tools. Suitable for low angle, low latitude casing surveys. JORPs are available.

Baker Hughes INTEQ *Seeker*

A first-generation north-seeking gyro, still in occasional use. It is a 'gyrocompassing' tool, meaning it can only take surveys when stationary and is therefore time-consuming to run. Suitable only for low angle, low latitude casing surveys. Not to be used for orientation surveys. JORPs are available.

Engineers should seek advice from UTG before programming the Seeker tool in their wells.

Scientific Drilling *Finder*

The *Finder* gyro is still used by Scientific Drilling for steering work, but has otherwise been superseded by the *Keeper*. The tool lacks the *Keeper*'s Z-axis gyro, so surveys must be taken with the tool stationary (gyrocompassing) up to an inclination of 15°. Below that depth, the tool may be run continuously to TD, with periodic drops for drift tuning. The *Finder* is an accurate, field-proven tool and may still be used with confidence if a *Keeper* is not available JORPs are available.

Ferranti *FINDS*

The only purely inertial survey tool ever manufactured. Very accurate. Formerly run by Eastman (now INTEQ), but progressively decommissioned in the mid 1990s. 10-3/4" OD, hence used exclusively for 13-3/8" and larger casing surveys.

Sperry-Sun *BOSS*

An optically referenced surface recording gyro tool, now obsolete. Used for multishots and orientation single shots.

Camera-Based Gyro Tools

A class of optically referenced gyro tools, used primarily for multishots, but also for orientation single shots. Also called photo-mechanical gyro multishots and single shots (PGMS, PGSS). Particular types include **level-rotor gyros** and the **Sperry-Sun SU3**. Potentially accurate in shallow, low angle wells, but quickly lose accuracy with increasing depth and inclination. Susceptibility to drift and human error has made this class of tool virtually obsolete.

Engineers should seek advice from UTG before programming Camera-based gyro tools in their wells.

5.9 Depth Measurement

Along-hole depth measurement is a critical aspect of wellbore surveying. It has historically received less attention than it deserves in terms of innovation and quality assurance, probably because it is often provided by a 'third-party' and is rarely under the sole control of the survey company.

Drill Pipe Depth Measurement

APPLICATIONS

The drill pipe tally is used as the primary depth reference for all survey tools conveyed by or landed in the BHA. That is:

- MWD
- Electronic and camera-based magnetic multishots and single shots
- Gyro orientation / single shot surveys
- Drop gyro multishots

OPERATION

The drill pipe and BHA components are measured, usually on the pipe deck, with a steel tape. The Drillers then keep a tabular record, called the 'pipe tally' of all the drill string components in the well. Effects of stretch and thermal expansion are usually ignored.

As the drill string is raised and lowered in the hole, the exact bit depth is tracked by the 'geolograph' – part of the rig equipment connected electronically to the mudlogging and MWD units.

QUALITY ASSURANCE

Drill pipe tallies are prone to human error, and discrepancies occur regularly. Good practice, such as totalling joint lengths and stand lengths separately and checking their agreement will eliminate the vast majority of errors.

Where possible, the MWD engineer should keep his/her own independent depth tally, and seek to resolve any discrepancy with the driller's tally.

Wireline Depth Measurement

APPLICATIONS

Survey tools run on electric wireline and making use of its depth measurements are:

- Gyro and inertial multishot surveys (excluding *FINDS*)
- Dipmeters and other tools run with wireline logs

Both the Gyrodata *Battery/Memory* tool and SDC *Keeper* can be conveyed on non-conducting wireline. Unless the tool is landed in the BHA and disconnected, the slick line depth measurements – of at best variable quality – will be used as definitive.

EQUIPMENT DESCRIPTION

Electric wireline comes in several diameters: 5/16" (8mm), 7/16" (11mm) and 15/32" (12mm) being the most common. For 8mm line, the breaking load is about 10,000 lb, but the working load is normally limited to under 5,000 lb.

There are two means of measuring the wireline to produce a depth measurement – measuring wheels and magnetic marking.

Measuring wheels are made of hardened steel or invar, and have precisely calibrated circumferences. They abut the wireline and rotate as it is spooled in and out. Whole and partial rotations of the wheel are usually digitally encoded and sent electronically to the wireline unit surface system.

The **Kerr wireline measurement system** has two independent measuring wheels on opposite sides of the wireline. The wheel with the greater rate of rotation is always used for the definitive reading, to help guard against slippage.

Surface cable tension is typically measured using an electrical strain gauge. This may be part of the measuring wheel mechanism, or attached to one of the sheaves through which the wireline runs.

Another means of enhancing wireline depth accuracy is with magnetic marks. A magnetically marked wireline has areas of permanent magnetism precisely spaced along its length, usually every 25 m or 100 ft. The position of these marks can be read by a sensor to a precision of a few millimeters. The marks provide the definitive wireline measurement, with intermediate depths being determined with a measuring wheel.

OPERATION

On land rigs and platforms, establishing the zero reference for wireline depth is straightforward. On floating rigs, care must be taken to allow for tides, rig ballasting, and the effect of heave compensators.

At TD in the well, some survey companies discount the 'slack' taken in before the tool moves from the depth measurement. The amount of wireline taken in should always be recorded. Typical specification is 1.5/1000 maximum. This practice tends to result in a better final re-zero check.

In some operations, data from the cable tension sensor will be used within the depth measurement system to enable an instantaneous stretch correction to be applied.

QUALITY ASSURANCE

The primary quality measure for wireline depth is the re-zero check, made when the tool returns to surface. Specifications, detailed in JORPs, range from 0.1% to 0.2% of measured depth.

A totally independent check on the wireline measurement is provided by a **casing collar locator** (**CCL**). This is a magnetic sensor run with the survey tool which is tuned to detect casing joint connections. Unambiguous comparisons between the CCL log and wireline depths can usually only be made where the casing tally contains short 'pup joints'. In some operations the CCL log is monitored in real time to check for over-spooling of the wireline. In others, the CCL log may be used to recompute the entire survey referenced to the casing tally.

Another independent check, or correction, to wireline measurements relies on the detection of a **gamma-ray marker** in the casing shoe. The wireline measurement is referenced to the (known) depth of this marker, which is detected by a gamma-ray sensor run with the survey tool.

5.10 JORPs

JORPs stands for Joint Operating and Reporting Procedures – documents which describe the way in which survey services are to be conducted on BP Amoco operations. There is a separate JORPs document for each vendor of survey services. MWD and other survey tools also have separate JORPs. The documents are written jointly by the survey vendor and BP Amoco UTG, but are maintained and distributed by the vendor.

Content

Each JORPs document is a distillation of best practice developed over many years of experience with each survey service. They are designed to:

- Ensure each survey service is used only for appropriate jobs
- Describe the special checks or corrections which are to be applied to the data

- Define the quality measures and associated tolerances which define survey acceptability
- Outline any special reporting requirements, both of survey quality and the data itself

The purpose of JORPs is to ensure that each survey service performs at the accuracy attributed to it by its approved error model.

Use of JORPs is a critical step in the design-execute process central to technical integrity.

Status and Responsibilities

JORPs have the status of Recommended Practices. Operations groups should be able to justify any deviation from them on sound technical grounds. Help with interpretation, dispensation or apparent conflicts can always be sought from UTG.

It is the responsibility of the survey service provider to make sure their engineers and supervisors are familiar with the content and status of JORPs, have a copy at the rigsite, and report any non-conformances.

It is the responsibility of drilling personnel in the Business Unit to understand the importance of JORPs and to actively support their use. This is especially important when compliance will incur an (apparent) cost in terms of rig time.

Service Company	JORPs document	Tool Coverage								Remarks
		MWD	Inertial gyro	North-seeking gyro	Surface read-out gyro	Camera-based gyro	EMS	Camera-based magnetic	Tele-drift	
Anadrill	Anadrill MWD Surveying Procedures Manual*	✓								Anadrill internal procedures document. Adopted as replacement to obsolete MWD JORPs by BP Amoco.
Baker Hughes INTEQ	JORPs for Directional MWD	✓								
	BPX and BHI JORPs		✓	✓	✓	✓	✓	✓		
Halliburton / Sperry-Sun	JORPs for SSDS Directional MWD*	✓								A separate document describes Sperry-Sun's Interpolation in-field referencing service
	Surface Readout Gyroscope Operations for BPX			✓	✓					Covers the G2 and SRO gyros
Gyrodata	BP JORPs Manual*			✓			✓			
Scientific Drilling	BP JORPs*			✓	✓	✓	✓	✓	✓	Additional and complementary to SORPs, SDC's internal standard.

* Under revision at time of writing

Table 5.8 JORPs documents currently in use

Section 6
Technical Integrity

Contents

Section 6

Technical Integrity

How to minimise the risk of a gross well positioning error and establish an auditable trail from target definition to definitive survey.

The parts of the Drilling and Well Operations Policy dealing with well positioning are exacting without being prescriptive. Beyond the requirements for a formal risk assessment and a review by a qualified Company Specialist, there is no definition of what constitutes an adequate level of technical integrity. This section illustrates what a fully competent directional and survey process looks like, and describes the key elements which the Company Specialist would look for in his/her review.

In order to satisfy the requirements of Policy, well positioning processes similar to those described in this section must be in place and in use.

6.1 What is Technical Integrity ?

In this Handbook, technical integrity is taken to mean the demonstrable fulfilment of two objectives:

- Adherence to certain defined technical standards
- Minimisation of the risk of gross error

Anyone making an independent assessment of technical integrity will want to:

- Be convinced that these two objectives were met on previous wells (this requires a documentary trail)
- Be confident that they will be met on future wells (this requires a fixed process or 'quality system')

6.2 Risk Assessment

The starting point for the examination of technical integrity is a risk assessment. For well positioning, this is usually a three-stage process:

1. Identify all the possible failures of planning, execution or evaluation which would seriously jeopardise the delivery of the well positioning objectives.
2. Match each possible failure with a prevention mechanism in the quality system.
3. Where no such prevention mechanism exists, develop one and incorporate it in the quality system.

This 'bottom-up' analysis has a number of powerful features:

- The failure identification phase encourages a 'brain-storming' approach, unconstrained by existing process or practice. This fresh perspective provides an 'independent check' on the quality system as a whole
- It demonstrates the direct role of each check, approval and control point in preventing a potential failure
- The resulting quality system is demonstrably 'complete' in a sense not possible for a 'top-down' equivalent

Failure Mode and Effects Analysis (FMEA)

One approach to the failure identification phase of the risk assessment is a Failure Mode and Effects Analysis. This is an established technique in which, starting with an undesired event, such as a well collision or a missed target, all the possible causes are listed. A hierarchy of causes and effects can be represented in the form of a tree, with the 'leaves' representing the root-cause (primary) failures which must be prevented by the quality system. Figure 6.1 is a generic example of an FMEA, which combines the undesired events 'missed target' and 'well collision' in one diagram.

Note that the occurrence of a statistically extreme survey error is not classified as a failure, but as an **on-design** event. This piece of jargon means that the probability of this happening is taken proper account of in the well plan, while all the other root-causes are assumed to have been managed out of the process.

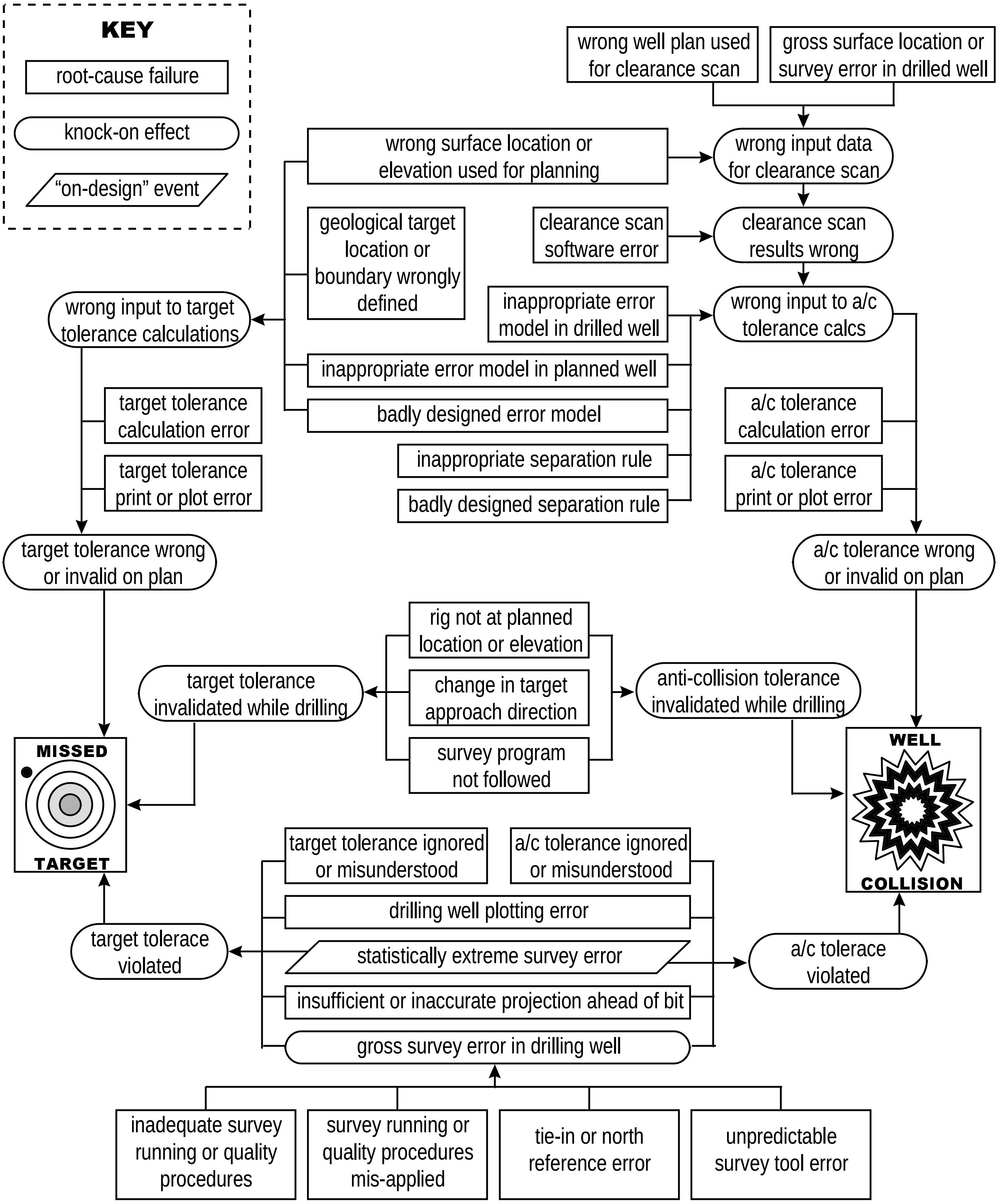


Figure 6.1 Generic failure mode and effects analysis for missed target and well collision

Categorisation of Potential Failures

The collection of root-cause failures included in figure 6.1 would make a good starting point for the critical assessment of any directional and survey quality system. These are grouped by subject area in the following table.

A.	DIRECTIONAL SOFTWARE / STANDARDS	
	1.	Clearance scan software error
	2.	Badly designed error model
	3.	Badly designed separation rule
	4.	Target tolerance calculation error
	5.	Anti-Collision tolerance calculation error
B.	DIRECTIONAL DATABASE	
	6.	Missing data, surface location or survey error in drilled well
	7.	Inappropriate error model in drilled well
C.	PLANNING DATA	
	8.	Wrong surface location or elevation used for planning
	9.	Geological target location or boundary wrongly defined
D.	DIRECTIONAL PLANNING	
	10.	Wrong well plan used for clearance scan
	11.	Inappropriate error model in planned well
	12.	Inappropriate separation rule
	13.	Target tolerance printing/plotting error
	14.	Anti-Collision tolerance printing/plotting error
E.	RIG POSITIONING	
	15.	Rig not at planned location or elevation
F.	SURVEY OPERATIONS	
	16.	Survey program not followed
	17.	Inadequate survey running or quality procedures
	18.	Survey running or quality procedures mis-applied
	19.	Unpredictable survey tool error
G.	DIRECTIONAL DRILLING OPERATIONS	
	20.	Change in target approach direction
	21.	Target tolerance ignored or misunderstood
	22.	Anti-Collision tolerance ignored or misunderstood
	23.	Drilling well plotting error
	24.	Insufficient or inaccurate projection ahead of bit
	25.	Tie-in or north reference error

Table 6.1

Generic classification of potential failures in the directional and survey process

6.3 Surface Positioning

➔ Section 3.1 describes some of the theory and techniques of surface positioning

The entire contents of this Handbook relies upon the assumption that the well's surface position is correct to a known level of accuracy. Technical integrity in surface positioning is therefore of the first importance and a pre-requisite of any drilling operation. The technical detail of surface positioning is outside the scope of the Handbook – practices vary widely between land and offshore wells, and between fixed and mobile drilling units. The few common principles are summarised here.

The Well Location Memorandum

➔ Appendix C includes an example of a Well Location Memorandum

The WLM is a formal document designed to ensure the planned surface and sub-surface locations of a well are defined unambiguously and in accordance with the well's objectives. The form includes the following sections:

- Target location(s), defined by the Geologist/Geophysicist in terms of the seismic in-line and X-line, or work-station co-ordinates. Target tolerances may also be included
- Target co-ordinates, computed from location data by a Company Surveyor, or other qualified surveyor
- Surface/seabed location, defined by Subsea Engineer or Drilling Engineer in terms of existing infrastructure or desired directional profile
- Surface/seabed co-ordinates, computed from location data by a Company Surveyor, or other qualified surveyor

Each data item is subject to an independent check, followed by approval by the Wells Team Leader.

The WLM, and the process which it controls, is best placed under the stewardship of Surveyors in the UTG Seismic Quality and Survey Team.

The Final Well Position Memo

Definitive well surface/subsea co-ordinates must be issued by a qualified surveyor. Company Surveyors will typically issue a Final Well Position Memo, giving the final co-ordinates, positioning system, and an estimate of the accuracy. This memo, the information in which is sent to the relevant regulatory agencies as well as the BU Wells team, should also be copied to the person with responsibility for directional survey management, and treated as defining the definitive as-built well location.

➔ Appendix B includes completed examples of a Final Well Position Memo and a final Well Location Data Form

The data used to compute the final well co-ordinates, including the primary and secondary positioning systems, subsea systems and co-ordinate transformations used, are recorded by a Surveyor on a **Final Well Location Data Form**. This form supports the Final Well Position Memo, and is usually retained by the Surveyors for their own records.

Facility and Slot Co-ordinates

Nomenclature relating to structure and slot positions may change between the facility design and operational phases. Make sure and up-to-date Surveyor's report is available.

Unexpected changes to structure or slot co-ordinates on the directional database may occur due to operator errors, software errors, or database errors. While such events are rare, the risk should be eliminated by a simple check. The best procedure is to keep a master paper copy of the structure and slot co-ordinates. At the start of the well planning process, the well planner should obtain structure and slot location reports from the database, check them against the master, and include them in the Directional Design File.

6.4 The Directional Design

The Directional Design for a well is the name given to the collection of inter-related proposals, programs, instructions and drawings which are the final product of the directional and survey planning process. Typically, this will include:

- Proposed well trajectory
- Survey program and procedures
- Reduced driller's target
- Wellsite drawings
- Well shut-in instructions

Other related items, such as BHA designs and well shut-in procedures are unlikely to be generated by the well planner using directional planning software and are not discussed further here.

The Directional Design File

The Directional Design File is the hard-copy documentation which the well planner produces in support of a completed Directional Design. Its dual purpose is to act as a self-contained reference for the individual who checks the Design, and as a permanent, auditable record of the Design. This will be important should an incident occur during the drilling of the well.

The Directional Design File must contain all the information necessary to make a thorough check on the integrity of the directional plan and survey program. Data not included in the file, for example full-size wellsite drawings and electronic data stored on the Directional Driller's computer, must also be checked as part of the integrity assurance process.

Contents of the Directional Design File

The Directional Design File must contain full details of the well's positioning objectives and sufficient material to demonstrate that the final design will achieve them. The following items, or their equivalents, will therefore be needed:

- Directional Design Check List. Similar to the example in Appendix C. This acts as a check on the contents of the file, as an aide-memoire for the Well Planner, and as a signature sheet for the Sign-off Authority (see below)

GEOLOGICAL OBJECTIVES

- Well Data Pack or equivalent document. Usually issued by the BU sub-surface team, this gives details of the well's geological positioning objectives. It will help the subsequent checking process if the Well Planner highlights the directly relevant data (position co-ordinates, target boundary points etc.)
- Updates to the geological objectives. These should be generated by the BU sub-surface team, be dated, and state exactly which information they supersede
- Printouts of the target locations as entered into the directional software

REFERENCE DATA

- Well Location Memorandum (for mobile rigs)
- Well Plan Data Sheet. Similar to the example in Appendix C. This sheet gives basic positional data for the well – precisely the data which should be reconfirmed by the BU before the wellsite drawings are produced

DESIGN DETAILS AND INSTRUCTIONS

- Proposed trajectory listing. For wells with complex target tolerances, it is useful to include a written confirmation from the BU sub-surface team that the proposal meets the well's geological objectives

- A4 (or 8.5"x11") plan and section drawings of the proposal. These are not essential, but are a useful visual aid when checking the design
- Survey Program Data Sheet. Similar to the example in Appendix C
- Anti-Collision Instruction Sheet. Similar to the example in Appendix C

ANTI-COLLISION ANALYSIS

- Proximity scan against all nearby wells. Some software packages produce scan summary sheets which contain sufficient detail to justify the selection of the reduced well set against which detailed calculations are performed
- Minimum separation calculations for all interfering wells
- A Tolerable Collision Risk Worksheet (➔ 4.4, C) for each well classified as minor risk

OTHER DESIGN ANALYSES

- Analysis for each target, showing the driller's target and the confidence level at which it was calculated

➔ Section 4.2 has details of the relief well drilling contingency requirement

- Printout of survey position uncertainty on entering and while drilling the reservoir. Highlight the data which confirms compliance with the relief well drilling contingency requirement

➔ Section 4.2 has details of this calculation

- Calculation of depth interval over which magnetic interference from nearby wells is likely. This data must be taken into account in the survey program. Where the software does not produce a special report, the calculation may be based on proximity scans

DISPENSATIONS

- Dispensations from Recommended Practice. Similar to the example form in Appendix C. Dispensations are discussed later in this section

Checking the Directional Design

The safety-critical and value-critical nature of the Directional Design demands that a thorough check be made that:

- All parts of the Design are consistent with each other
- It fulfils the positioning objectives of the well
- It complies with all relevant standards and procedures

THE SIGN-OFF AUTHORITY

The person responsible for this check may be termed the Sign-off Authority. As the name implies, this person is responsible (the BU remains accountable) for the technical correctness of the Directional Design and associated wellsite drawings and instructions, and will probably be the last person to examine it in detail. The Sign-off Authority must have a thorough knowledge of directional well planning and survey program design and must be familiar with BP Amoco's directional and survey standards and procedures as described in this Handbook. The Sign-off Authority need not be organisationally independent of the well Planner, provided he/she performs the design check independently.

It is the responsibility of the Sign-off Authority to find all the shortcomings of the Directional Design File, whether missing, incorrect or superfluous data, and to ensure each is corrected.

THE SEVEN FUNDAMENTALS OF DIRECTIONAL DESIGN CHECKING

For the purposes of technical integrity assurance, the Sign-off Authority is <u>not</u> required to check all engineering aspects of the suitability of the plan for the well. Indeed, there are only seven fundamental facts which he/she must confirm:

1. That the proposed trajectory has the correct surface, target entry and TD locations.

That the proposed survey program is sufficient to ensure that:

2. The geological target will be intersected and all other geological steering requirements met.

3. The risk of drilling an unsuccessful relief well is minimised.

4. Any gross error in a survey will be detected.

5. An adequate definitive survey will be obtained.

6. That adherence to the anti-collision instructions, including the tolerance lines on any anti-collision diagram will prevent violation of the appropriate minimum well separation rule for all nearby wells.

7. That the instructions and drawings submitted to the wellsite team are accurate and sufficient to enable them to correctly execute the Design.

Detailed Checks

A pre-requisite for a thorough directional design check is familiarity with the Well Data Pack (or equivalent document) and the development Directional Basis of Design (if it exists). The Sign-off Authority must then satisfy his/herself that the seven fundamentals have been met. A number of specific checks and procedures which facilitate this are listed here.

PROPOSED TRAJECTORY HAS THE CORRECT SURFACE, TARGET ENTRY AND TD LOCATIONS

➔ Section 6.6 discusses the relationship between directional databases.

- Check that the well has been created on the well planning database and that:
  * The structure and slot locations correspond with the definitive data (usually a Well Location Memorandum for new drills and a Final Well Position Memo or as-built drawing for sidetracks)

* The well originates from the correct slot
* The vertical datum details (KBE or RTE, water depth etc.) are correct

- Check that the final well plan on the database matches the proposed trajectory in the Directional Design File. If the trajectory is planned from a point in an existing well:
  * Check from the Well Data Pack or drilling program that the plan starts at the correct depth
  * Review the survey program and surveys from which the well has been planned
  * Confirm that the surveys to which the well plan is tied represent the correct, definitive, well profile for the parent well
- Identify the target location(s) in the Well Data Pack and calculate their drilling grid co-ordinates and TVD below drilling zero elevation (KBE or RTE)
- Check (by interpolating if necessary) that the proposed trajectory passes through all the target location(s)

SURVEY PROGRAM IS SUFFICIENT TO INTERSECT TARGET AND MEET OTHER GEOLOGICAL REQUIREMENTS

- If the survey program is or should be stored on the well planning database, check that it matches the program in the Directional Design File
- Identify the geological boundary of each target in the Well Data Pack and check that they match the geological target boundaries used in the target analyses

- Review the target analysis report (or hand calculations) for each target and, for each, check that:
  - * The correct target has been selected
  - * The position uncertainty has been calculated using the correct well path (ie. the final proposed trajectory) and the correct combination of survey tools
  - * An appropriate level of confidence has been applied (usually, 99%, 95% or 90%. If a smaller value has been used, there should be written confirmation from the BU that this is acceptable)
- Identify any other geometrical constraints or confidence limits from the Well Data Pack and Directional Basis of Design and check that the Directional Design File has supporting documentation demonstrating that each is met. Examples are:
  - * Inclination constraints
  - * Lateral and TVD deviation constraints in the reservoir
  - * Lateral and TVD uncertainty constraints
  - * Dog-leg severity constraints

RISK OF DRILLING AN UNSUCCESSFUL RELIEF WELL IS MINIMISED

➔ Relief well contingency requirements are in Section 4.2

- Check that a calculation has been made of the absolute position uncertainty of the last casing shoe before entering the target, and that this is in compliance with the relief well contingency requirement
- Check that the survey data which will be acquired in the hole section in which each target is to be penetrated is of the type specified by the relief well contingency requirement

  If either of these requirements is not met, BU dispensation will be required

ANY GROSS ERROR IN EACH SURVEY INSTRUMENT WILL BE DETECTED

- Check that the survey program and procedures are sufficient to ensure that a gross error in any tool will always be detected. There are three acceptable ways of validating tool performance:
  * Overlap with another tool type
  * Check shots at a common depth with a different tool of the same type
  * Use of diagnostic survey processing software (currently only applicable to in-field referenced MWD and electronic multishots)

AN ADEQUATE DEFINITIVE SURVEY WILL BE OBTAINED

- Check that the survey program and procedures will not leave any significant unsurveyed or poorly surveyed hole intervals

ADHERENCE TO ANTI-COLLISION INSTRUCTIONS WILL PREVENT VIOLATION OF MINIMUM WELL SEPARATION RULES

- Check that the global proximity scan was performed:
  * With the final proposed trajectory
  * Against a suitably wide and comprehensive selection of offset wells
  * With a sufficiently wide volume of coverage
- Compare the list of wells for which minimum separation calculations have been performed against the results of the global clearance scan (and, if necessary, the travelling cylinder base plot). Minimum separation calculations must be performed for any well which could possibly impinge on the drilling tolerances

- Check that the minimum separation calculations were performed:
  * With the final proposed trajectory
  * With the correct survey program
- Read the anti-collision instructions and TCR worksheets (if any). Use them to check that:
  * The appropriate minimum separation rule has been selected for each interfering well
  * For wells where calculations have been performed for more than one rule, the correct rule had been applied in each depth interval
- For each interfering well:
  * Reality check the minimum separation calculations
  * Check that the minimum tolerable separations at each depth are represented correctly as no-go areas on the travelling cylinder plot (or working diagram)
- For each completed anti-collision diagram:
  * Assess whether it is adequately clear, legible and uncluttered
  * Check the proposal version number, depth interval and key to tolerance lines
  * Check that entry into every no-go area on the working diagram is prohibited by a tolerance line. In cases where it is not, assess whether violation of the no-go area is feasible given the other restrictions on the diagram

WELLSITE INSTRUCTIONS AND DRAWINGS ARE CLEAR, ACCURATE AND SUFFICIENT

- Check that the directional information which will be sent to the rig is complete, correct and unambiguous. This includes the survey program and anti-collision instructions

- Check that the Directional Driller's rigsite database has been initialised correctly with:
  * The correct surface co-ordinates
  * The final proposed trajectory
  * The survey program (where applicable)
  * The correct vertical section details

The following checks apply to the Plan and Section drawing(s):

- Make sure that the drawing(s) cover the whole planned section of the well at a scale large enough for accurate manual plotting of the as-drilled well path
- Check that each drawing is annotated with:
  * The correct well name
  * The proposal identifier or version number
  * The survey reference direction (True or Grid, plan views only)
  * The value of magnetic declination to be used for the well (plan views only, check the value against the Well Plan Data Sheet and the latest BGS global geomagnetic model (➔ 3.2)
  * The vertical section origin and azimuth (vertical section projections only, check the values match those on the directional database)
- Select at least two points from the proposed trajectory listing. Scale off the corresponding point on the plan and section drawings and check that the plotted well path passes through it. (Don't just check the surface location and target – these will be correct even if the wrong version of the well plan has been plotted)

- Check that all the driller’s targets are shown on the drawing(s), are labelled as such, and that they match the target analysis calculations
- Check that any other drilling restrictions (eg. due to geological requirements) which are represented on the drawing(s) are clear and correct
- Check that any other information shown on the drawing(s) is correct and unambiguous

Correction and Sign-Off

Problems with the Directional Design File may range in severity from a possibly ambiguous label on a drawing to a gross misinterpretation of the well's objectives. Whatever the nature of the problem or discrepancy, each must be discussed with the Well Planner before corrective action is taken.

When substantial changes are required to any part of the Design, the Well Planner and Sign-off Authority must take care that all related analyses are re-examined and, if necessary, repeated. For example, any change to the survey program will have a knock-on effect on the target analyses, the anti-collision diagrams and the relief well criterion.

When checking is complete and all corrections have been made, the Sign-off Authority should sign the Directional Design File and Wellsite Drawings to confirm that:

- The well has been planned according to the procedures specified by BP Amoco and the Sign-off Authority's organisation
- The design meets all the seven fundamental requirements for directional and survey technical integrity
- The information in the Directional Design File, including the wellsite drawings, is complete and correct

Business Unit Approval

Unless they are fulfilling the role of the Sign-off Authority, BU drilling engineers are not usually expected to make comprehensive and detailed checks of the directional design. As a minimum however, they should check (and the directional company should insist that they check) the following details:

- That the surface, target and bottom hole co-ordinates of the proposed trajectory are correct. This data is all on the Well Plan Data Sheet
- That the proposed trajectory is realistic and does not compromise any planned operation, such as wireline logging or running the completion
- That the survey program is consistent with the drilling/casing program and that any operational risks associated with surveying (such as periods when the drill pipe must be stationary) are minimised

DISPENSATIONS FROM RECOMMENDED PRACTICE

Violation of the Drilling and Well Operations Policy requires the express permission of Business Unit Management and Drilling Management. This should rarely be required for directional and survey issues. However, occasions may arise where the violation of standards or recommended practices given in this Handbook or in BU-specific documents are justified. Whatever the local division of responsibilities, there should be an established process for such dispensations, and it should meet the following criteria:

- The details, justification and authorisation of the dispensation should be recorded on a form designed for the purpose. The information on the form should include
  - Rig name, Well name
  - Procedure / Standards Document. This is the document which contains the procedure or standard from which dispensation is sought. For example:

➔ Appendix C contains an example dispensation form

* Specific Procedure / Standard. The policy, procedure, tolerance, minimum standard etc. from which dispensation is sought. Numerical values should be given where appropriate

* Details of Dispensation Requested. The procedure to be missed out, the extent of violation of the tolerance or standard etc

* Justification. A brief argument covering why normal practice is inappropriate or impractical and the nature of the additional risks incurred by not following it

* Attachments. Calculation sheets, completion diagrams etc

- Each request for dispensation should be reviewed independently by a qualified directional specialist
- Subject to the specialist review, the dispensation should be authorised by a senior member of the BU Wells team

6.5 Executing the Design

Careful design of a fit-for-purpose directional program is pointless unless the program is followed at the wellsite. This will only happen consistently if the execution of the program is actively monitored. This monitoring must not only ensure that the elements of the design are followed, but that the assumptions within the design, such as survey tool performance, are tested for validity.

WELLSITE AUTHORITY LIMITATIONS

The scope enjoyed by the rig team for altering the design based on circumstance should be clearly understood.

Certain rules (such as not crossing anti-collision tolerance lines and following JORPs) are inflexible.

Some instructions, such as survey station interval, and the shape of the final build profile, may (or may not) be open to modification. Instructions sent to the wellsite must differentiate between what it mandatory and what is at the discretion of the rig team.

WELLSITE SURVEY VALIDATION

Thorough analysis and validation of survey data may take several days, particularly if the tools must be returned to base. It is clearly impractical to wait this long before drilling ahead or setting casing. Thus wellsite survey QA, including comparison with surveys previously acquired, must be sufficient to enable decisions on tool change-out or re-survey to be made. Since re-survey at a later time may be impractical, the default decision should be:

When in doubt, re-survey.

HANDLING NON-CONFORMANCE

Any non-conformance with the Directional Design, or failure of any assumption implicit in it, must be assumed to jeopardise the well's positioning objectives. Non-conformance may take several forms:

- Failure to follow survey program
- Failure to follow standard survey procedures
- Survey tool failure or operating out-of-spec
- Violation of a directional constraint, eg. crossed tolerance line or exceedence of maximum dog-leg severity

In all these cases, the process by which confidence in the design is reinstated is the same:

1. Non-conformance is reported by rig or office team.

➔ Appendix C contains a Non-Conformance Report form suitable for this

2. In potentially serious cases, the incident should be investigated and a written summary of the events made.

3. A design review to assess the impact on the well's positioning objectives should be made.

4. Remedial actions of two types should be taken:

   a) A new design, program change or instruction should be developed, to safeguard the well's objectives.

   b) Specific measures, such as training or new process checks should be instigated to prevent re-occurrence.

6.6 Survey Data Management

The Well Survey File

The definitive survey for a well never tells the whole story. Data from other tools run in the well, quality checks, survey comparisons, reports and incidental notes may each be invaluable to the survey expert should the position of the well need to be reappraised. Such reappraisals are rare, but are usually critically important when they occur – collision situations, equity disputes and reservoir remodelling are examples.

This supporting data should be kept in a single location – the Well Survey File, and retained for the life of the field. Typical contents would be:

- The survey program (planned and actual)
- All survey tool data, including field results and final reports

- Quality measures, including well site QA sheets and survey data comparisons
- The definitive survey

➔ Survey data comparisons are discussed in Section 4.10

Survey Reporting

It is important that all survey data acquired in the well is properly reported, both electronically and on hard copy. This includes multishots, MWD surveys and other data, such as from dipmeters, that is to be used for well positioning. The main function of the hard copy report is as a permanent record of the definitive data, associated quality measures, and any other information which may be of future use.

An important secondary function of the report is to place accountability for data quality firmly with the survey vendor. This is particularly important for MWD surveys, which are frequently reported not by the MWD company, but second-hand by the Directional Driller. All MWD companies should prepare a final well survey report listing the all the surveys taken in the well.

The contents of a final survey report should include:

- The definitive data
- A statement, signed by the individual(s) responsible for the data quality, that it was acquired and checked according to standard procedures and has passed all applicable quality specifications
- For magnetic tools, details of the BHA and the magnetic spacing of survey sensors
- Details of all the corrections applied to the data, including the values used for magnetic declination and grid convergence, if applicable
- Any associated quality measures including, where appropriate, a completed Wellsite Survey QA Sheet

- Discussion of any serious problems encountered during the data acquisition, especially any which could impact data quality

Survey Validation

Acquiring data over the planned depth intervals is not sufficient to fulfil the requirements of the survey program. The data from each tool must also pass certain checks which indicate it has performed with its expected accuracy, so that it can be assigned an appropriate approved error model. This is called 'validation'.

Failure to pass these checks invalidates the survey program, so should be carefully investigated by survey experts immediately. The default response to such failures is tool change-out and a repeat survey. Any other response must be justified by a thorough review of the consequences of the failure on the well's survey objectives.

There is a general rule that

> *unvalidated survey data should never be loaded on the definitive directional database*

since the data will later inevitably be assumed to conform to it's assigned error model. This rule should never be violated for operational wells. For historical wells, where the survey data is frequently without any indication of quality, practicalities may force it to be broken. In such cases, the data should be assigned a highly conservative error model.

The two main methods of validation are survey data comparison (➔ 4.10) and internal tool quality checks, discussed with the individual tools. For several tools these internal checks are summarised on a wellsite survey QA sheet.

WELLSITE SURVEY QA SHEETS

These forms record the quality measures for individual surveys, and indicate pass/fail criteria. Their completion at the wellsite by the survey engineer is stipulated in JORPs and is therefore **mandatory**. The sheets should be signed off at the rig by a BP Amoco representative and included in the Well Survey File.

Definitive Surveys

! BP Amoco Standard Practice

The definitive survey for a wellbore is the final estimate of the well's position made from an analysis and compilation of all the available survey data. The following comprise a Standard Practice for the construction of definitive surveys:

1. Definitive surveys must be compiled for all wellbores, including abandoned sidetracks, fish etc. These must be stored on the directional database in such a way that they are included automatically in clearance scans.
2. The definitive survey will extend from the Well Reference Point (typically ground level or mud-line) to the driller's total depth.
3. Sections of the well surveyed with different tools will be differentiated on the directional database, and each section will be assigned the approved error model which most closely corresponds with the data.
4. Where there is a choice of survey data over a section of the wellbore, the most accurate data will be used in the definitive survey, provided it has been fully reviewed and satisfactorily validated. A large-scale T-plot (➔ 4.10) showing all the data in the well is an excellent basis for this final review.
5. Actual survey stations will be stored, not interpolated points.
6. Straight line extrapolation will be used from the last survey station to Driller's total depth. An exception may be made when this last part of well contains a deliberate and significant direction change.

PUBLISHING THE DATA

If the definitive directional database and applications are networked, it is a comparatively simple task to trigger a customised program whenever a definitive survey is created or changed. At a simple level, this program may send an e-mail to the sub-surface database administrators alerting them to the new data. With increased integration of applications, the use of subsidiary databases is set to decline.

Database Management

Data management is an important technical discipline in its own right. The Drilling and well Operations Policy requirement that directional data be managed according to a life-of-field strategy (➔ 2.2) heightens the importance of proper controls on the database. This section discusses the main issues and describes some of the best practices which have been developed within BP Amoco.

DATA CRITICALITY

The level of control to which directional data is subject will vary depending on its criticality. At the top of the list is data describing the physical position of the Company's assets:

- Single well and multi-well structure surface co-ordinates and elevations
- Definitive surveys

Next in rank is supporting data and data which defines a directional design:

- Drilling rig elevations
- Target names, locations and tolerances
- Rig / well / slot / target allocations
- Survey programs and individual survey tool results
- Proposed well trajectories

Finally, there is peripheral or transitory data:

- Drilling plots
- Vertical section details
- BHA details

DEFINITIVE DATABASE

Operational expediency often requires that the same directional data is stored in several places. Whenever this occurs, one database should be nominated as definitive and maintained as such. This helps settle issues of data flow and access control.

The definitive database need not be the same for all data types. For example, definitive surface positions may be held by the Survey group, definitive wellbore surveys by the Drilling group, and definitive target locations by the Subsurface group.

Nominating a database as definitive does not mean that its content is beyond question. All discrepancies between databases should be investigated and resolved using whatever source data is available. Blindly copying data from the definitive database onto other databases may not only propagate an error, but may eliminate the chance of detecting it in the future.

ACCESS RESTRICTIONS

Most databases and applications allow for different users to have just the access permissions they need to do their job. Use of this facility has two advantages:

- It prevents data from being viewed, edited or deleted by any but authorised users
- It gives unskilled users confidence to use the application, in the knowledge they cannot do any harm

Well designed databases stamp all critical data with the user name of the last person to edit it, together with the date and time. This provides a useful check for auditing, and reduces the need to check data in detail.

HARD-COPY DATA BACK-UP

It is good practice to keep printed copies of critical data, even when using the most robust database and applications. In particular, printouts of structure and well location details should be kept on file, together with the Surveyor's original definitive paperwork. The data held electronically on the directional database should be checked against these printouts at an early stage in the well planning process.

DIRECTIONAL DATABASE COMPARISONS

Project data held on databases which are not regularly reconciled with each other will rapidly diverge. If a directional service company plans wells on its own in-house software, it can probably best maintain the underlying project data through regular bulk copying from the BP Amoco definitive database. The frequency and scope of these bulk copies will depend on the extent to which the service company's database is used for critical operations.

BP Amoco has developed special software for detailed comparison of drilling and subsurface directional databases. The first and most successful example was developed in Alaska, where the databases concerned were DEAP and PDB respectively. The comparison script ran automatically every week, producing a report of the following discrepancies:

- Wells with definitive surveys on only one database
- Wells with surface positions (defined by mapping grid easting and northing) differing by more than 2 ft
- Wells with bottom hole locations (defined by mapping grid easting and northing and TVDss) differing by more than 5 ft

Some tolerance must be set on the positional discrepancy, to allow for minor differences in survey and co-ordinate calculation methods.

USER VIGILANCE

Whether or not all the above safeguards are in place, the user of directional data should still view all results with a critical eye. A prime example is anti-collision scan summaries. The well planner should always make a quick check that the list of wells scanned includes all those to be expected, and no wells that should not appear (for example wells assigned to the wrong field).

6.7 Performance Review

Whether or not learning cycles and continuous improvement fall within the realm of technical integrity is a matter of definition. Nevertheless, no operation can be considered fit-for-purpose which fails to address these issues. The indispensable building blocks of any directional survey learning process are briefly discussed in this section.

PERFORMANCE MEASURES

Meaningful measurement is a pre-requisite of sustained performance improvement. So long as improved performance is the goal, it is less important that measures be 'fair' (in the sense of being directly comparable between Business Units or service companies) as that they drive the right behaviours. A measured improvement in performance should always coincide with real benefits to the Company.

With some imagination, performance measures can be devised for every stage of the directional/survey process. Some examples:

- Planning
  - Number of innovations

  * Turn-around time on designs and design modifications
  * Number of well shut-ins or total deferred production
- Operations
  * Survey cost per 10,000 ft
  * No of tool failures
  * No of BHAs used
- Deliverables
  * Wellbore tortuosity
  * Target intersection confidence
  * Measured depth excess over plan

➔ Calculation of tortuosity is explained in Section A.6

TECHNICAL INVESTIGATIONS

Operational pressures act as a powerful disincentive against time-consuming post-analysis of tool failures or disagreements between surveys. All such occurrences, unless they are investigated, understood and acted upon, <u>will</u> occur again, perhaps with more severe consequences.

Every tool failure or significant disagreement between surveys should be carefully investigated. A brief report of the investigation, however inconclusive, should be included in the Well Survey File. Any lessons which are applicable to future jobs should be included immediately in the relevant knowledge base.

KNOWLEDGE BASE

In BP Amoco, directional survey knowledge is stored where it will be directly used. The principal repositories are:

- <u>*JORPs*</u>

  Any lessons from operational or data quality problems may make a suitable addition to JORPs.

- *Approved survey error models*

  These models are subject to regular review, to ensure they incorporate the latest investigations into survey errors and remain in line with field experience.

- *This Handbook*

  The point-of-contact for all these is the Directional and Survey Specialist, UTG Well Integrity Team. Suggestions regarding JORPs can also be made directly to the service companies involved.

Appendix A
Mathematical Reference

Contents

Appendix A
Mathematical Reference

Contents (cont'd)

Appendix A

Mathematical Reference

Some of the equations and formulae underlying the methods described in the main part of the Handbook.

This appendix is intended as a technical reference for existing directional software, and as a guide for programmers and engineers intending to write survey analysis spreadsheets or applications.

A.1 Minimum Curvature Survey Calculation

The equations for minimum curvature survey calculation are as follows:

$$\Delta N = \frac{\Delta MD}{2}\left[\sin I_1 \cos A_1 + \sin I_2 \cos A_2\right].RF$$

$$\Delta E = \frac{\Delta MD}{2}\left[\sin I_1 \sin A_1 + \sin I_2 \sin A_2\right].RF$$

$$\Delta V = \frac{\Delta MD}{2}\left[\cos I_1 + \cos I_2\right].RF$$

where the Radius Factor is defined by $RF = \frac{2}{DL}\tan\left(\frac{DL}{2}\right)$

and the dog-leg by

$$\cos DL = \cos(I_2 - I_1) - \sin I_1 \sin I_2 [1 - \cos(A_2 - A_1)]$$

To avoid a singularity in straight hole, it is necessary either to set $RF = 1$ when DL is less than some fixed angle X, or to use the following truncated series expansion when DL is less than some fixed angle Y:

$$RF = 1 + \frac{DL^2}{12} + \frac{DL^4}{120} + \frac{17DL^6}{20160}$$

If the fixed values obey $X < 0.01°$ and $Y < 13°$, the resultant error will be less than 1 part in 10^9.

A METHOD FOR REVERSE SURVEY CALCULATION

A similar method, also based on interpolating the hole direction, can be found in **How to get the best results from well-surveying data,** World Oil, April 1986

Several solutions have been published for the problem of calculating depth, inclination and azimuth from position data. The following method is based on the geometry of the circle.

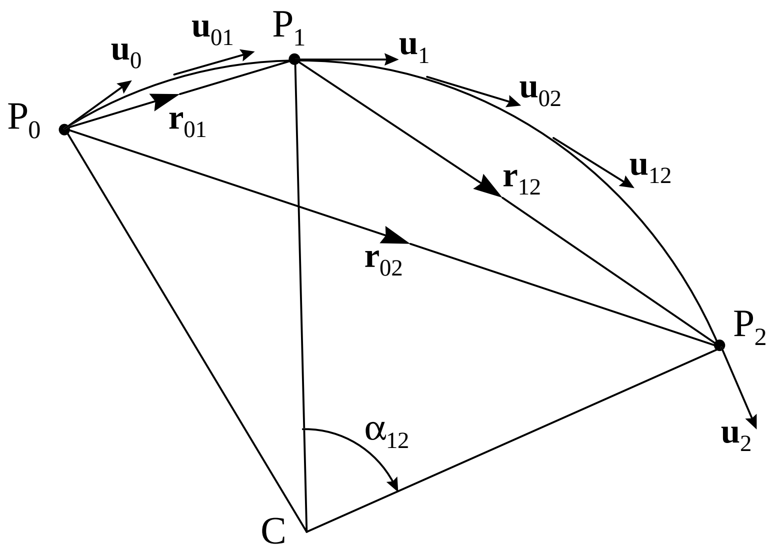


Figure A.1

Reverse survey calculation

The three consecutive survey stations P_0, P_1 and P_2 lie on a unique circular arc (or straight line). The wellbore direction at P_1 is approximated by the unit direction vector, $\mathbf{u}_1$ of the arc as it passes through this point. It is given by interpolation:

$$\mathbf{u}_1 = \frac{r_{12}}{r_{02}}\mathbf{u}_{01} + \frac{r_{01}}{r_{02}}\mathbf{u}_{12}$$

If P_0 is the first station, and its unit direction vector is not already known, it can be estimated by observing that:

$$\mathbf{u}_0 + \mathbf{u}_1 = 2\mathbf{u}_{01}\cos\left(\frac{1}{2}\angle P_0CP_1\right) = 2\mathbf{u}_{01}\cos\left(\angle P_0P_2P_1\right) = 2\mathbf{u}_{01}\left(\mathbf{u}_{12}.\mathbf{u}_{02}\right),$$

so that $\mathbf{u}_0 = 2\mathbf{u}_{01}\left(\mathbf{u}_{12}.\mathbf{u}_{02}\right) - \mathbf{u}_1$

Likewise, if P_2 is the last station, $\mathbf{u}_2 = 2\mathbf{u}_{12}\left(\mathbf{u}_{01}.\mathbf{u}_{02}\right) - \mathbf{u}_1$

The wellbore direction at all stations having been determined, the measured depth increment between consecutive stations is obtained by assuming (as with minimum curvature), that they are connected by circular arcs. From the direction change and 3D distance between consecutive stations,

$$\Delta D_{12} = r_{12}\frac{\alpha_{12}}{2}\csc\left(\frac{\alpha_{12}}{2}\right) \quad \text{where } \alpha_{12} = \sin^{-1}\left|\mathbf{u}_1 \times \mathbf{u}_2\right|$$

A.2 Position Covariance and Error Ellipses

Position uncertainty in three-dimensions is usually represented in the form of a 3x3 covariance matrix:

$$\text{3D covariance matrix} = \mathbf{C}_{nev} = \begin{bmatrix} \sigma_n^2 & \sigma_{ne} & \sigma_{nv} \\ \sigma_{ne} & \sigma_e^2 & \sigma_{ev} \\ \sigma_{nv} & \sigma_{ev} & \sigma_v^2 \end{bmatrix}$$

Geometrically, this uncertainty may be represented in the form of an ellipsoid, but the complexity of the mathematical derivation of its dimensions and orientation outweigh its usefulness to the engineer.

Transformation to Borehole-Referenced Axes

The earth-referenced axes (north, east, vertical) are those naturally produced by the position uncertainty calculation. These may be transformed to the more intuitive borehole-referenced axes (highside, lateral, along-hole] by pre- and post-multiplying by a rotation matrix:

$$\mathbf{C}_{hla} = \begin{bmatrix} \sigma_h^2 & \sigma_{hl} & \sigma_{ha} \\ \sigma_{hl} & \sigma_l^2 & \sigma_{la} \\ \sigma_{ha} & \sigma_{la} & \sigma_a^2 \end{bmatrix} = \mathbf{T}_{hla}\mathbf{C}_{nev}\mathbf{T}_{hla}^T$$

where

$$\mathbf{T}_{hla} = \begin{bmatrix} \cos I \cos A & \cos I \sin A & -\sin I \\ -\sin A & \cos A & 0 \\ \sin I \cos A & \sin I \sin A & \cos I \end{bmatrix}$$

And I, A are the local wellbore inclination and azimuth.

Horizontal Position Uncertainty

There are two ways of thinking about horizontal well position uncertainty: (a) the uncertainty in the horizontal co-ordinates of a given point in the well (b) the uncertainty in the position where the well intersects a given vertical depth. (a) is the quantity most usually reported and plotted by directional software. (b) is the more physically meaningful and useful quantity.

UNCERTAINTY OF A POINT IN THE WELL

This is obtained by projecting the 3 dimensional ellipsoid onto the horizontal plane, which eliminates the vertical component of uncertainty. The uncertainty is represented by the 2 dimensional covariance matrix:

$$\mathbf{C}_{ne} = \begin{bmatrix} \sigma_n^2 & \sigma_{ne} \\ \sigma_{ne} & \sigma_e^2 \end{bmatrix}$$

UNCERTAINTY AT A GIVEN VERTICAL DEPTH

This is obtained by pre- and post-multiplying the 3 dimensional covariance matrix by a transformation matrix:

$$\mathbf{C}^*_{ne} = \begin{bmatrix} \sigma_n^{*2} & \sigma_{ne}^* \\ \sigma_{ne}^* & \sigma_e^{*2} \end{bmatrix} = \mathbf{T}^*_{ne}\mathbf{C}_{nev}\mathbf{T}^{*T}_{ne}$$

where $\mathbf{T}^*_{ne} = \begin{bmatrix} 1 & 0 & -\tan I \cos A \\ 0 & 1 & -\tan I \sin A \end{bmatrix}$

CALCULATION OF HORIZONTAL ERROR ELLIPSES

The standard error ellipse in the horizontal plane of a given point in the well is calculated as follows:

$$\text{Semi-major axis} = \sigma_{\max} = \sqrt{\frac{\sigma_n^2 + \sigma_e^2 + \sqrt{\left(\sigma_n^2 - \sigma_e^2\right)^2 + 4\sigma_{ne}^2}}{2}}$$

$$\text{Semi-minor axis} = \sigma_{\min} = \sqrt{\frac{\sigma_n^2 + \sigma_e^2 - \sqrt{\left(\sigma_n^2 - \sigma_e^2\right)^2 + 4\sigma_{ne}^2}}{2}}$$

The azimuths of these axes, ψ_{maj} and ψ_{min}, can be found from the two solutions of:

$$\tan 2\psi = \frac{2\sigma_{ne}}{\sigma_n^2 - \sigma_e^2}$$ which lie between -90° and +90°.

To decide which is which, it is enough to note that:

If $\sigma_n^2 > \sigma_e^2$ then $-45° < \psi_{\text{maj}} < +45°$

If $\sigma_n^2 < \sigma_e^2$ then $-45° < \psi_{\text{min}} < +45°$

The error ellipse for the well position at a given vertical depth is calculated from the covariance matrix $\mathbf{C}^*_{ne}$ in exactly the same way.

Confidence Levels for Ellipses and Ellipsoids

Table 3.4 shows the number of standard deviations at which a (2 dimensional) error ellipse must be drawn to correspond to various levels of confidence. This table may be extended, or a similar table drawn up for 3D ellipsoids, with the aid of a book of statistical tables or by using the 'CHIDIST' and 'CHIINV' statistical functions in Microsoft Excel. We use the table of percentile values of the Chi-Square distribution:

If $\chi^2_{p,\nu}$ is the tabulated value for probability p for the distribution with ν degrees of freedom, then the $\sqrt{\chi^2_{p,\nu}}$ -sigma error ellipse (ν=2) or ellipsoid (ν=3) is a confidence region of confidence level p.

Example. Find the number of standard deviations at which a 3D error ellipsoid must be drawn to represent a 95% confidence region, assuming the well position errors follow a trivariate normal distribution.

Setting p = 0.95 and ν = 3, we find from tables that $\chi^2_{0.95,3}$ = 7.81. The 95% confidence region is therefore represented by a 2.79-sigma error ellipsoid.

The Pedal Curve or 'Footprint'

The radius of the error ellipse in any direction does not represent the positional uncertainty in that direction. In fact, the uncertainty in the horizontal direction with azimuth A is:

$$\sigma_A = \begin{bmatrix}\cos A & \sin A\end{bmatrix}\begin{bmatrix}\sigma_n^2 & \sigma_{ne} \\ \sigma_{ne} & \sigma_e^2\end{bmatrix}\begin{bmatrix}\cos A \\ \sin A\end{bmatrix} = \sigma_n^2 \cos^2 A + \sigma_{ne} \sin 2A + \sigma_e^2 \sin A$$

The curve whose radius in every direction A is equal to this expression is called the pedal curve or 'footprint'. It is variously described as being dumb-bell or peanut shaped. Figure A.2 shows how the curve is constructed from tangents to the standard error ellipse.

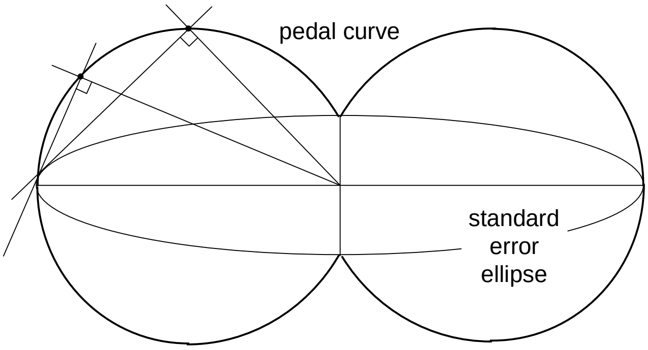


Figure A.2

Geometrical construction of the pedal curve

Figure A.3 is a (schematic) illustration, showing the correspondence between the pedal curve radius in the north and east directions with the standard deviation of the distribution in those directions.

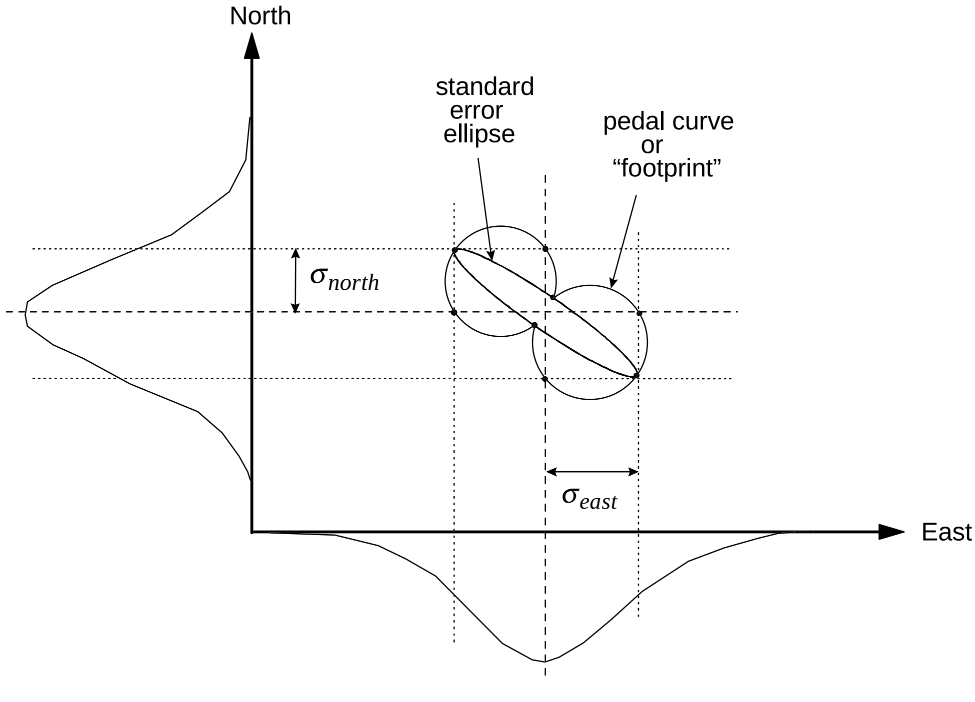


Figure A.3

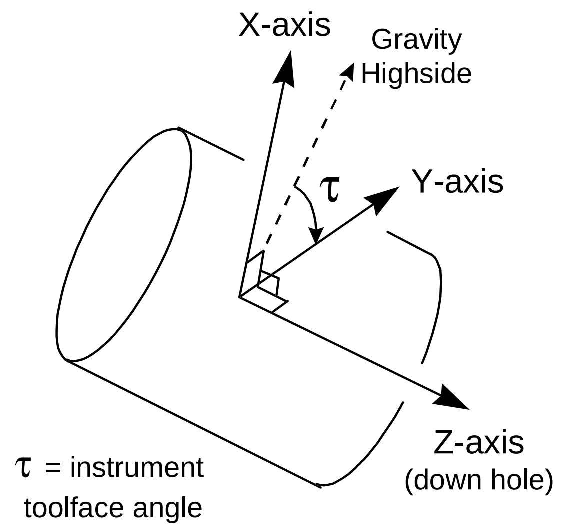
The pedal curve and uncertainties in the north and east directions

A.3 MWD Tool Calculations

Naming conventions for MWD sensors vary between companies (notably Schlumberger). This section uses the following labels:

Figure A.4

Naming convention for sensor axes



The accelerometer measurements, G_x, G_y, G_z and magnetometer measurements, B_x, B_y, B_z are used in combination to determine hole inclination, (magnetic) azimuth and tool orientation as follows:

$$Inclination = I = \cos^{-1}\left(\frac{G_z}{\sqrt{G_x^2 + G_y^2 + G_z^2}}\right) \text{ or } \sin^{-1}\left(\frac{\sqrt{G_x^2 + G_y^2}}{\sqrt{G_x^2 + G_y^2 + G_z^2}}\right)$$

$$Magnetic\ Azimuth = A_m = \tan^{-1}\left(\frac{\left(G_x B_y - G_y B_x\right)\sqrt{G_x^2 + G_y^2 + G_z^2}}{B_z\left(G_x^2 + G_y^2\right) - G_z\left(G_x B_x + G_y B_y\right)}\right)$$

$$Instrument\ toolface = \tau = \tan^{-1}\left(\frac{G_x}{G_y}\right)$$

The inverse relations, which give the theoretical sensor readings at any tool orientation are:

$$G_x = -G \sin I \sin \tau$$

$$G_y = -G \sin I \cos \tau$$

$$G_z = G \cos I$$

$$B_x = B \cos\Theta \cos I \cos A_m \sin\tau - B \sin\Theta \sin I \sin\tau + B \cos\Theta \sin A_m \cos\tau$$

$$B_y = B \cos\Theta \cos I \cos A_m \cos\tau - B \sin\Theta \sin I \cos\tau - B \cos\Theta \sin A_m \sin\tau$$

$$B_z = B \cos\Theta \sin I \cos A_m + B \sin\Theta \cos I$$

where G, B and Θ are the gravity field intensity, magnetic field intensity and magnetic dip angle respectively.

These three physical quantities can be estimated from the tool sensor readings as follows:

$$\textit{Gravity Field Intensity} = \sqrt{G_x^2 + G_y^2 + G_z^2}$$

$$\textit{Magnetic Field Intensity} = \sqrt{B_x^2 + B_y^2 + B_z^2}$$

$$\textit{Magnetic Dip Angle} = \sin^{-1}\left(\frac{G_x B_x + G_y B_y + G_z B_z}{G.B}\right).$$

A.4 Target Analysis Calculations

Two algorithms for calculating a driller's target are given here. The BP Amoco method is implemented in software and gives a precise answer for all wellbore and target orientations. The graphical method can be done by hand, but is only applicable to horizontal targets.

BP Amoco Method

Given a geological target boundary and a positional uncertainty covariance matrix and bias vector (evaluated for the point of intersection of the proposal with the target plane), it is required to calculate the inclusion probability at an array of points within the target boundary. The inclusion probability at a point of interest is defined as the probability that the true well position intersects the geological target given that the surveyed well position passes through the point of interest.

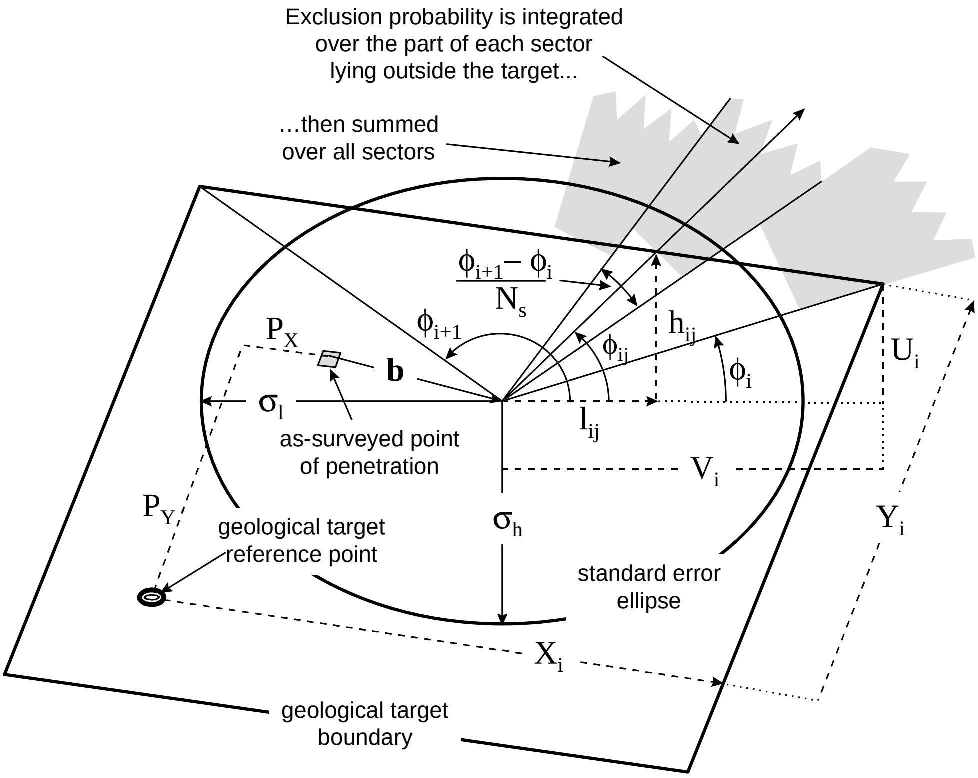


Figure A.5

A 'bit's-eye-view' of the target: the basis of the BP Amoco target analysis method

Suppose the target plane has dip (ie. tilt from horizontal) δ and dip azimuth (ie. azimuth of down-dip direction) α. Define a grid on the target plane with origin at the target reference point, X-axis horizontal with azimuth $\alpha - 90°$ and Y-axis pointing up-dip.

Suppose the geological target boundary has N_v vertices with co-ordinates X_i, Y_i on the target plane and define $\mathbf{x}_i = \begin{pmatrix} X_i \\ Y_i \end{pmatrix}$

Suppose the as-surveyed position of the bit as it penetrates the target is $\mathbf{p} = \begin{pmatrix} P_X \\ P_Y \end{pmatrix}$ with survey uncertainty represented by earth-referenced covariance matrix $\mathbf{C}_{\text{nev}}$ and survey bias (from survey position to most likely position) by earth-referenced vector $\mathbf{b}$.

‘BIT’S-EYE VIEW’ OF THE TARGET BOUNDARY

The position in the target plane of vertex *i* with respect to the bit is $\mathbf{x}_i - \mathbf{p}$

The position in earth-centred (NEV) co-ordinates is obtained by multiplying by the transformation matrix

$$\mathbf{T}_{tp} = \begin{pmatrix} \sin\alpha & -\cos\delta\cos\alpha \\ -\cos\alpha & -\sin\alpha\cos\delta \\ 0 & -\sin\delta \end{pmatrix}$$

Allowing for survey bias, the expected position of the vertex with respect to the bit is

$$\mathbf{T}_{tp}(\mathbf{x}_i - \mathbf{p}) + \mathbf{b}$$

Further multiplying by the transformation matrix

$$\mathbf{T}_{tc} = \begin{pmatrix} \cos I\cos A & \cos I\sin A & -\sin I \\ -\sin A & \cos A & 0 \end{pmatrix}$$

gives the expected vertex position in travelling cylinder co-ordinates:

$$\begin{pmatrix} U_i \\ V_i \end{pmatrix} = \begin{pmatrix} highside \\ lateral \end{pmatrix} = \mathbf{T}_{tc}\left[\mathbf{T}_{tp}(\mathbf{x}_i - \mathbf{p}) + \mathbf{b}\right]$$

PDF OF THE TRUE BIT POSITION

The next task is to find the probability density function (pdf) of the true bit position, in travelling cylinder co-ordinates relative to the expected bit position. The covariance matrix representing the position uncertainty of the bit in travelling cylinder co-ordinates is:

$$\mathbf{C}_{tc} = \begin{pmatrix} \sigma_h^2 & \sigma_{hl} \\ \sigma_{hl} & \sigma_l^2 \end{pmatrix} = \mathbf{T}_{tc}\mathbf{C}_{nev}\mathbf{T}_{tc}^T$$

with corresponding probability density function

$$pdf(\mathbf{t}) = \frac{1}{2\pi\sqrt{\det(\mathbf{C}_{tc})}} \exp\left(-\frac{1}{2}\mathbf{t}^T\mathbf{C}_{tc}^{-1}\mathbf{t}\right)$$

$$= \frac{1}{2\pi\sqrt{\sigma_h^2\sigma_l^2 - \sigma_{hl}^2}} \exp\left(\frac{-h^2\sigma_l^2 + 2hl\sigma_{hl} - l^2\sigma_h^2}{2\left(\sigma_h^2\sigma_l^2 - \sigma_{hl}^2\right)}\right)$$

where the vector $\mathbf{t} = \begin{pmatrix} h \\ l \end{pmatrix}$ represents a general position in the travelling cylinder plane.

INCLUSION PROBABILITY

The probability that the true bit position lies in a given sector and outside the target is the integral of the pdf over the portion of the sector outside the target.

Making the change of variables $\begin{pmatrix} h \\ l \end{pmatrix} \to \begin{pmatrix} r\cos\phi \\ r\sin\phi \end{pmatrix}$ gives

$$pdf(r,\phi) = \frac{1}{2\pi\sqrt{\sigma_h^2\sigma_l^2 - \sigma_{hl}^2}} \exp\left(-r^2 f(\phi)\right)\sqrt{\det\left(\frac{\partial(h,l)}{\partial(r,\phi)}\right)}$$

$$= \frac{r}{2\pi\sqrt{\sigma_h^2\sigma_l^2 - \sigma_{hl}^2}} \exp\left(-r^2 f(\phi)\right)$$

where $f(\phi) = \dfrac{\sigma_l^2\cos^2\phi - \sigma_{hl}\sin 2\phi + \sigma_h^2\sin^2\phi}{2\left(\sigma_h^2\sigma_l^2 - \sigma_{hl}^2\right)}$

If the arc between the i^{th} and $(i+1)^{\text{th}}$ vertices is divided into a large number N_s of equal sectors, then the required integral for the j^{th} sector is approximated by:

$$I_{ij} \approx \int_{r=\sqrt{h_{ij}^2+l_{ij}^2}}^{r=\infty} \left(\int_{\phi=\phi_i+(j-1)\frac{\phi_{i+1}-\phi_i}{N_s}}^{\phi=\phi_i+j\frac{\phi_{i+1}-\phi_i}{N_s}} pdf(r,\phi)\, d\phi \right) dr$$

where $\begin{pmatrix} h_{ij} \\ l_{ij} \end{pmatrix}$ is the intersection of the centre-line of the sector with the target boundary expressed in travelling cylinder co-ordinates and $\phi_i = \tan^{-1}\left(\frac{U_i}{V_i}\right)$ is the angle in the travelling cylinder plane from the expected bit position to the ith target vertex measured anti-clockwise from the lateral axis.

By approximating the pdf across the width of the sector by its value on the centre-line,

$$I_{ij} \approx \frac{\phi_{i+1}-\phi_i}{N_s} \int_{r=\sqrt{h_{ij}^2+l_{ij}^2}}^{r=\infty} pdf(r,\phi_{ij})\, dr$$

where $$\phi_{ij} = \phi_i + \left(j-\frac{1}{2}\right)\frac{\phi_{i+1}-\phi_i}{N_s}$$

This integral may be evaluated exactly:

$$I_{ij} = \frac{\phi_{i+1}-\phi_i}{N_s} \frac{1}{2\pi\sqrt{\sigma_h^2\sigma_l^2-\sigma_{hl}^2}} \int_{r=\sqrt{h_{ij}^2+l_{ij}^2}}^{r=\infty} r \exp\left(-r^2 f\left(\phi_{ij}\right)\right) dr$$

$$= \frac{\phi_{i+1} - \phi_i}{N_s} \frac{1}{2\pi\sqrt{\sigma_h^2 \sigma_l^2 - \sigma_{hl}^2}} \left[\frac{-\exp\left(-r^2 f\left(\phi_{ij}\right)\right)}{2 f\left(\phi_{ij}\right)} \right]_{r=\sqrt{h_{ij}^2 + l_{ij}^2}}^{r=\infty}$$

$$= \frac{\phi_{i+1} - \phi_i}{N_s} \frac{\exp\left\{-\left(h_{ij}^2 + l_{ij}^2\right) f\left(\phi_{ij}\right)\right\}}{4\pi f\left(\phi_{ij}\right)\sqrt{\sigma_h^2 \sigma_l^2 - \sigma_{hl}^2}}.$$

To evaluate $h_{ij}^2 + l_{ij}^2$, we write down the equations of the two lines on which $\begin{pmatrix} h_{ij} \\ l_{ij} \end{pmatrix}$ lies:

(a) centre-line of the sector: $h = l \tan \phi_{ij}$

(b) ith edge of target: $\dfrac{l - V_i}{h - U_i} = \dfrac{V_{i+1} - V_i}{U_{i+1} - U_i}$

Solving for l gives $$l_{ij} = \frac{V_i\left(U_{i+1} - U_i\right) - U_i\left(V_{i+1} - V_i\right)}{\left(U_{i+1} - U_i\right) - \left(V_{i+1} - V_i\right)\tan \phi_{ij}}$$

so that

$$h_{ij}^2 + l_{ij}^2 = l_{ij}^2 \tan^2 \phi_{ij} + l_{ij}^2 = \frac{l_{ij}^2}{\cos^2 \phi_{ij}} = \left[\frac{V_i\left(U_{i+1} - U_i\right) - U_i\left(V_{i+1} - V_i\right)}{\left(U_{i+1} - U_i\right)\cos\phi_{ij} - \left(V_{i+1} - V_i\right)\sin\phi_{ij}} \right]^2$$

The inclusion probability for the point is found by summing the exclusion probability for all sectors and edges and subtracting from unity:

Inclusion probability at point **p** $= 1 - \sum_{i=1}^{N_v} \sum_{j=1}^{N_s} I_{ij}\left(\mathbf{p}\right)$

Graphical Method

The following method for calculating the driller's target will give adequate results for horizontal targets. The resulting target will have a confidence level of approximately 98% (that is, the inclusion probability at all points on the driller's target boundary will be about 98%). For sloping targets, the geometry becomes more complex and software should be used.

STEP 1

Calculate the while-drilling survey uncertainty and bias on reaching the target. Denote the bias and one standard deviation uncertainty in the highside direction by (b_H, σ_H) and the same quantities in the lateral direction by (b_L, σ_L). Suppose the planned well azimuth at the target is A.

STEP 2

Draw the geological target boundary on a piece of graph paper.

STEP 3

Now draw the geological target again, but shifted a horizontal distance $\left(2\sigma_H - b_H\right)/\cos Inc$ along azimuth A from its true position, where Inc is the hole inclination through the target.

STEP 4

Draw the geological target again, shifted a horizontal distance $\left(2\sigma_H + b_H\right)/\cos Inc$ along azimuth A+180° from its true position.

STEP 5

Draw the geological target again, shifted a horizontal distance $2\sigma_L - b_L$ along azimuth A+90° from its true position.

STEP 6

Draw the geological target a final time, shifted a horizontal distance $2\sigma_L + b_L$ along azimuth A-90° from its true position.

STEP 7

The driller's target is the area inside all the geological target outlines. Figure A.6 is an example.

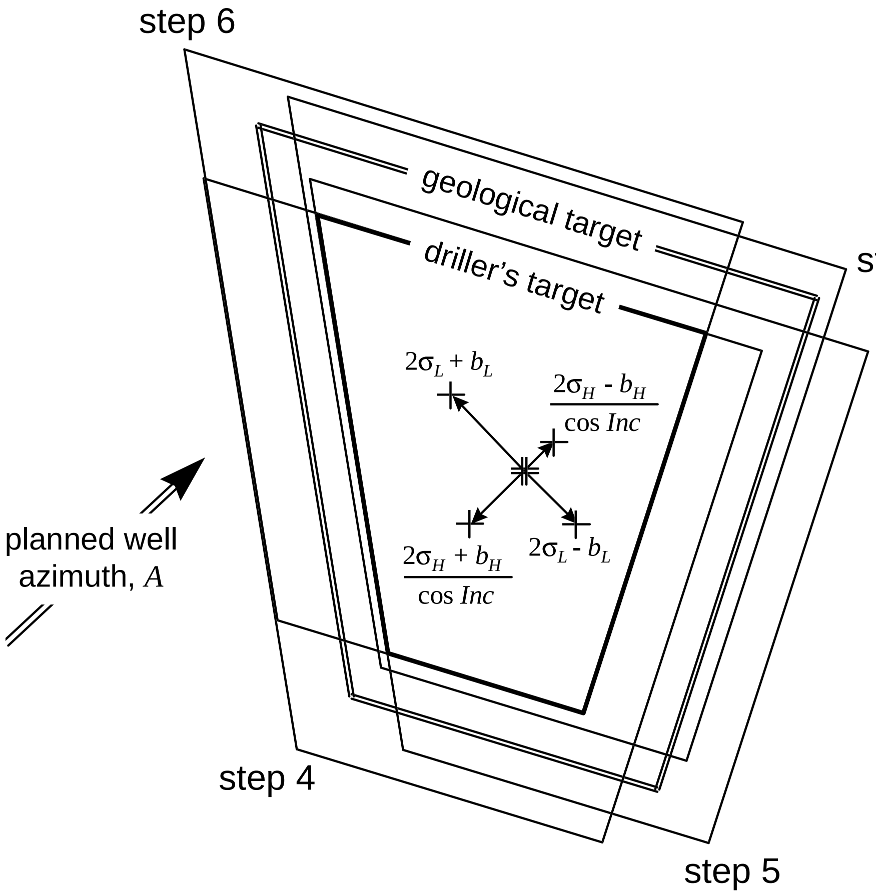


Figure A.6

Graphical method of target analysis

A.5 Anti-Collision Calculations

Minimum Separation Calculations

SURFACE POSITION UNCERTAINTY

The uncertainty in the relative surface locations of the planned and interfering wells is incorporated into the position uncertainty of the interfering well:

$$\sigma_2 = \sqrt{\sigma_{surf}^2 + \sigma_{hole}^2}$$

where σ_{surf} = Relative surface positional uncertainty between planned and interfering wells at 1 standard deviation

σ_{hole} = Interfering well survey positional uncertainty (relative to wellhead) at 1 standard deviation

ALLOWANCE FOR SURVEY BIAS

The allowance for survey bias is difficult to calculate correctly by hand, since it depends on the orientation and relative position of the two wells. An approximate method (which always errs on the side of caution) is to sum the "bias magnitudes" (the length of the bias vector) for both wells. The exact calculation to be used in directional software is:

$$S_b = Max \{ 0, \mathbf{u}.(\mathbf{b}_2 - \mathbf{b}_1) \}$$

where $\mathbf{u}$ = the direction from the interfering well

$\mathbf{b}_1, \mathbf{b}_2$ = the positional bias vectors in the planned and interfering wells respectively.

Note that when $\mathbf{u}.(\mathbf{b}_2 - \mathbf{b}_1)$ is negative, the predicted survey bias would increase the separation between the wells, allowing us (in theory at least), to reduce the minimum allowable separation. In practice, we ignore bias in this case, and only apply it when it works against us.

Calculation of No-Go Areas

The radius of the no-go line at an angle β from the interfering well (measured clockwise from 12 o'clock on the travelling cylinder plot) is calculated by:

i) calculating the direction of the radius in 3D-space from:

$$\mathbf{u} = \begin{bmatrix} \cos I \cos A \cos(\beta - A) - \sin A \sin(\beta - A) \\ \cos I \sin A \cos(\beta - A) + \cos A \sin(\beta - A) \\ -\sin I \cos(\beta - A) \end{bmatrix}$$

where:

I = Inclination in the planned well at the relative depth on the TC plot

A = Azimuth in the planned well at the relative depth on the TC plot

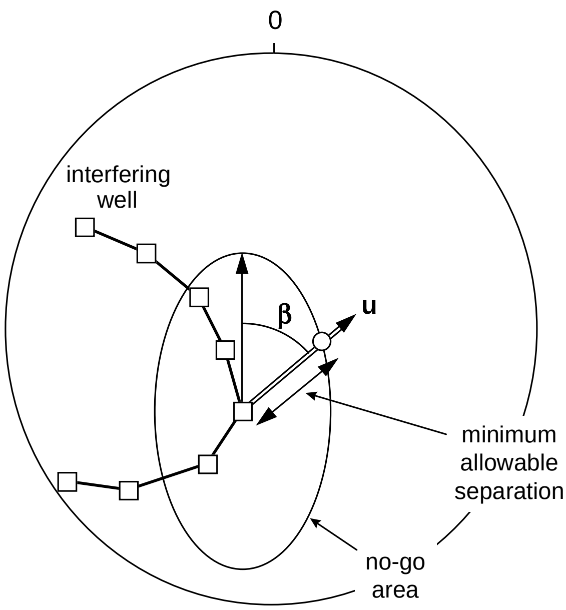


Figure A.7

Calculating a no-go area on the travelling cylinder diagram

ii) calculating the uncertainty in the planned and interfering wells from:

$$\sigma_1 = \sqrt{\mathbf{u}^T \mathbf{C}_1 \mathbf{u}} \qquad \sigma_2 = \sqrt{\mathbf{u}^T \mathbf{C}_2 \mathbf{u} + \sigma_{surf}^2}$$

where:

$\mathbf{C}_1$ = Planned well position covariance matrix

$\mathbf{C}_2$ = Interfering well position covariance matrix

σ_{surf} = Relative surface positional uncertainty between planned and interfering wells at 1 standard deviation

iii) substituting these uncertainty values into the standard equations for minimum allowable separation (➔ 4.3).

The Risk-Based Separation Rule

The general risk-based separation rule,

$$S = \sigma\sqrt{2\ln\left(\frac{d_1 + d_2}{P\sigma\sqrt{2\pi}}\right)} + \frac{d_1 + d_2}{2}$$

is derived in a straightforward way from the normal probability distribution. The argument is as follows. Consider the case of two straight wells crossing at a high angle of incidence. Figure A.8 represents their relative position along the line connecting the points of closest approach. Let S be the planned centre-to-centre separation, and σ be the uncertainty in the wells' relative position in this direction (we ignore survey bias in this derivation and include it in the minimum allowable separation later). We can use the assumption of normally distributed survey errors to write down the probability density function of the true distance, z, between the wells:

$$f(z) = \frac{1}{\sigma\sqrt{2\pi}} \exp\left\{-\frac{(z - S)^2}{2\sigma^2}\right\}$$

A collision will occur if the two wells approach closer than the sum of their radii, the probability of which is

$$P = \int_{-\frac{d_1+d_2}{2}}^{\frac{d_1+d_2}{2}} f(z)dz$$

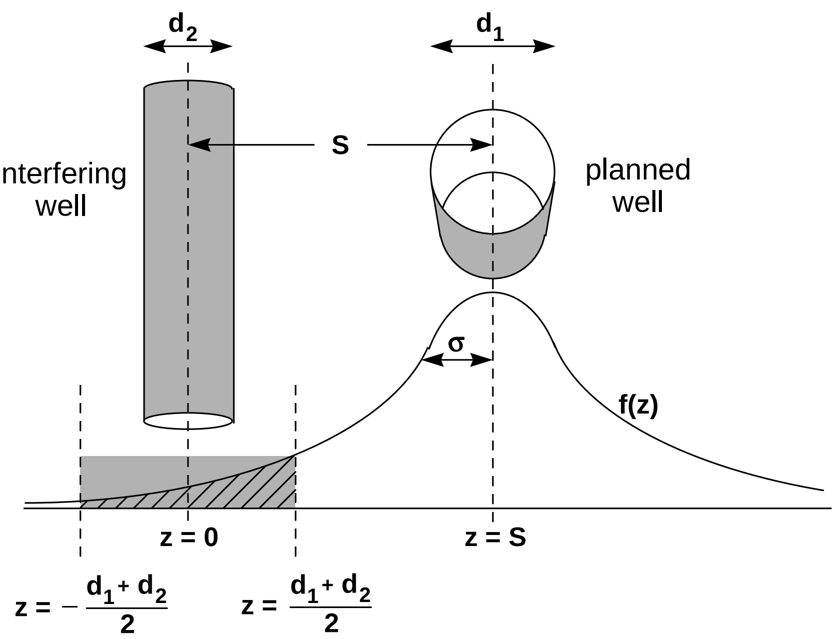
(the hatched area under the curve in figure A.8). We can approximate this area with the shaded rectangle (an over-estimate). Symbolically,

$$P \approx (d_1+d_2) f\left(\frac{d_1+d_2}{2}\right) = \frac{d_1+d_2}{\sigma\sqrt{2\pi}} \exp\left\{-\frac{\left[S-(d_1+d_2)/2\right]^2}{2\sigma^2}\right\}$$

Making S the subject of this equation gives our expression for minimum separation.

Figure A.8

Derivation of the risk-based separation rule



This expression has some peculiarities of behaviour. All are explicable in practical as well as mathematical terms, but can appear surprising initially.

When the position uncertainty of the wells is small (case 1), the minimum separation increases with increasing uncertainty, as is the case with conventional separation rules.

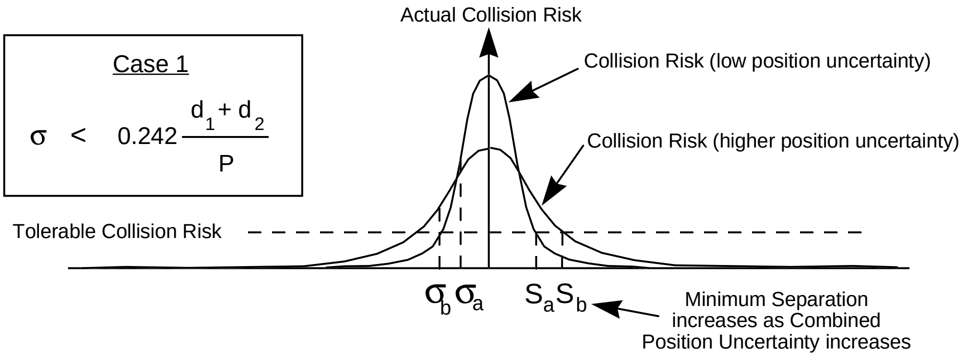


Figure A.9

Behaviour of the risk-based separation rule at low positional uncertainty

But the minimum allowable separation does not increase without limit. As the uncertainty increases, the probability of the interfering well being close to its surveyed position falls. Beyond a certain critical value of uncertainty, it becomes possible to drill closer to the interfering well for a given probability of collision (case 2). The minimum allowable separation now <u>decreases</u> with increasing uncertainty

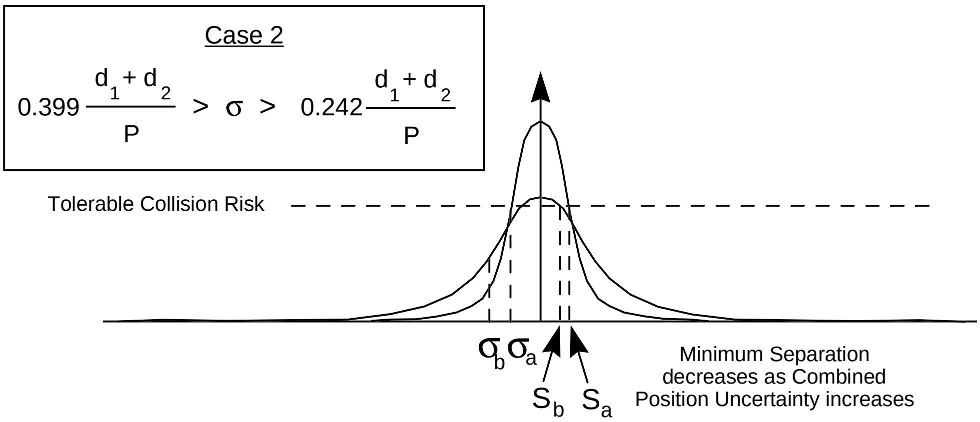


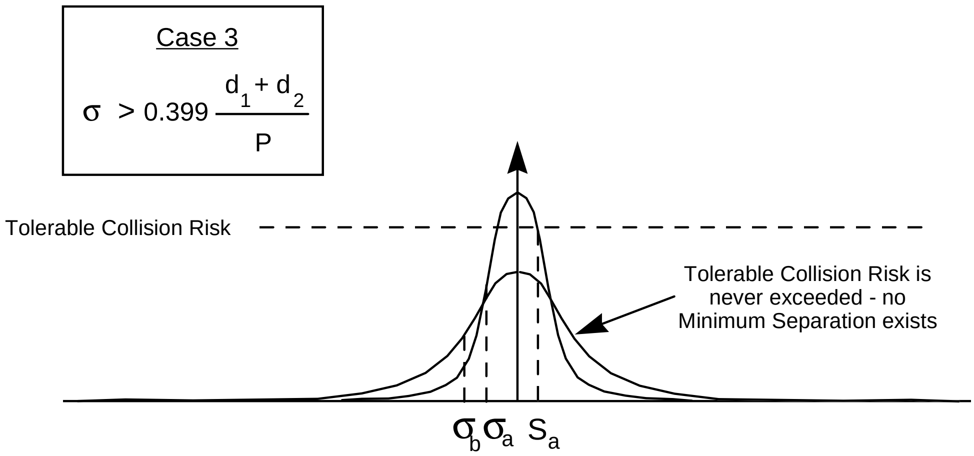
Figure A.10

Behaviour of the risk-based separation rule at intermediate positional uncertainty

Eventually, if we make the position uncertainty large enough, we reach a second critical value where even if we drill straight at the offset well, we are unable to exceed the tolerable collision risk (case 3). In this situation, there is no minimum well separation.

Figure A.11

Behaviour of the risk-based separation rule at high positional uncertainty



A.6 Tortuosity

The definition of tortuosity recommended by UTG is

the average excess dogleg severity over plan

A comparison is made between the final planned trajectory and the definitive survey. The two profiles should be compared over the same depth interval, so whichever is the longer of the plan or the definitive survey should be truncated back to the total depth, D_{TD}, of the shorter (the two start depths are assumed to be the same, D_0). This done, denote the well plan listing of measured depth, inclination and azimuth to be:

$$\begin{bmatrix} D_P^i & I_P^i & A_P^i \end{bmatrix} \qquad 0 \le i \le M$$

and the as-drilled definitive survey listing to be

$$\begin{bmatrix} D_S^j & I_S^j & A_S^j \end{bmatrix} \qquad 0 \le j \le N$$

From the equations for minimum curvature (➔ A.1), the angle change over a single arc of the well plan is:

$$DL_P^i = \cos^{-1}\left\{\cos\left(I_P^i - I_P^{i-1}\right) - \sin I_P^{i-1} \sin I_P^i \left[1 - \cos\left(A_P^i - A_P^{i-1}\right)\right]\right\}$$

and the average dogleg severity over the whole plan is:

$$DLS_P = \frac{1}{D_{TD} - D_0} \sum_{i=1}^{M} DL_P^i$$

Likewise, the average as-drilled dogleg severity is:

$$DLS_S = \frac{1}{D_{TD} - D_0} \sum_{j=1}^{N} DL_S^j$$

where

$$DL_S^j = \cos^{-1}\left\{\cos\left(I_S^j - I_S^{j-1}\right) - \sin I_S^{j-1} \sin I_S^j \left[1 - \cos\left(A_S^j - A_S^{j-1}\right)\right]\right\}$$

The tortuosity of the well is simply the difference of the two averages:

$$\textit{Wellbore Tortuosity} = DLS_S - DLS_P$$

Appendix B
Approved Tool Error Models

Contents

Appendix B

Approved Tool Error Models

An inventory of the survey tool error models approved for use in BP Amoco.

The inventory of BP Amoco validated and approved survey tool error models is updated regularly. These updates are reflected in regular changes to the models stored in BP Amoco's corporate drilling software. This appendix is therefore a snapshot. Details of changes post-dating this Handbook or advice on the correct application of the models can be obtained from the Directional and Survey Specialist, UTG.

The following points should be noted:

- Error models for different services may be identical. Maintaining different names for the same model enables the services to be identified in a survey program listing.
- The amount empirical evidence supporting each model varies widely. More detailed investigations of performance have been made for survey services which are in frequent use, particularly the higher accuracy tools.
- Many of the models differ substantially from those used and quoted by the survey tool vendors. Vendor models are often either unsupported by field data, or in a form different to the Industry standard.

The standard format for survey tool error models is described in **SPE 56702 Accuracy Prediction for Directional MWD**

Approved Error Model	Short Name (Compass)	Short Name (DIMS)	Application	Remarks
MWD - Standard	MWD	MWD	MWD with no (or no known) special corrections	The model allows for the fact that axial interference may marginally exceed the upper limit specified in Section 4.9 when the well is near to horizontal east/west
MWD + Sag correction	MWD+SAG	MWD+SG	MWD with a BHA deformation correction applied	Covers all BHA corrections, from simple 2D to finite-element 3D models
MWD + Short Collar correction	MWD+SCC	MWD+SC	MWD with single station axial interference correction applied (➔ 4.9)	"Short Collar" is the name of Sperry-Sun's correction, but the error model covers all such
MWD + Sag + SC corrections	MWD+SAG+SC	MWD+SS	MWD with both BHA sag correction and single station axial interference correction applied	
MWD + IHR correction	MWD+IHR	MWDIHR	In-hole referenced MWD (➔ 4.8).	Assumes a BHA sag correction is applied to enhance inclination accuracy
MWD + IFR correction	MWD+IFR	MWDIFR	In-field referenced MWD (➔ 4.7), with time-varying field applied. Model is applicable whether or not Short Collar type correction is applied.	Assumes a BHA sag correction is applied to enhance inclination accuracy.

Table B.1 Approved Survey Tool Error Models – MWD (Part 1 of 2)

Approved Error Model	**Short Name (Compass)**	**Short Name (DIMS)**	**Application**	**Remarks**
MWD + IFR [Alaska]	MWD+IFR:AK	MWDIAK	In-field referenced MWD in Alaska	Model takes account of increased violence of magnetic field disturbances in Alaska. Assumes a BHA sag correction is applied to enhance inclination accuracy
MWD + IFR [Wytch Farm]	MWD+IFR:WF	MWDIWF	In-field referenced MWD at Wytch Farm	Model takes account of observed low levels of axial low level interference using Anadrill BHA components and design. Assumes a sag correction is applied to enhance inclination accuracy
MWD + IFR + Multi-station	MWD+IFR+MS	MWDIMS	In-field referenced MWD with multi-station analysis and correction (➔ 4.9) applied in post-processing	Assumes a BHA sag correction is applied to enhance inclination accuracy
MWD + Crustal Anomaly corrn	MWD+crust	MWD+CA	MWD where local magnetic field has been measured (or derived from aero-magnetic data) and corrected for, but short-term time variations are not applied.	Assumes a BHA sag correction is applied to enhance inclination accuracy
MWD + Crustal + SC corrections	MWD+CA+SC	MWD+CS	Same as MWD + Crustal Anomaly correction but with single station axial interference correction applied	Assumes a BHA sag correction is applied to enhance inclination accuracy

Table B.1 Approved Survey Tool Error Models – MWD (Part 2 of 2)

Approved Error Model	Short Name (Compass)	Short Name (DIMS)	Application	Remarks
EMS - Standard	EMS	EMS	Electronic multishot with no (or no known) special corrections	Includes ex-BP "Electronic Single Shots" model. Assumes large axial interference errors have been corrected.
EMS + Sag correction	EMS+SAG	EMS+SG	Electronic multishot with a BHA deformation correction applied	Covers all BHA corrections, from simple 2D to finite-element 3D models. Assumes large axial interference errors have been corrected.
EMS + IHR correction	EMS+IHR	EMSIHR	In-hole referenced electronic multishot (➔ 4.8).	Assumes a BHA sag correction is applied to enhance inclination accuracy.
EMS + IFR correction	EMS+IFR	EMSIFR	In-field referenced electronic multishot (➔ 4.7), with time-varying field applied. Model is applicable whether or not Short Collar type correction is applied.	Assumes a BHA sag correction is applied to enhance inclination accuracy.
EMS + IFR [Alaska]	EMS+IFR:AK	EMSIAK	In-field referenced electronic in Alaska	Model takes account of increased violence of magnetic field disturbances in Alaska. Assumes a BHA sag correction is applied to enhance inclination accuracy
EMS + Crustal Anomaly corrn	EMS+crust	EMS+CA	Electronic multishot where local magnetic field has been measured (or derived from aero-magnetic data) and corrected for, but short-term time variations are not applied.	Assumes large axial interference errors have been corrected.

Table B.2 Approved Survey Tool Error Models - Electronic Magnetic Multishots

Approved Error Model	Short Name (Compass)	Short Name (DIMS)	Application	Remarks
BHI RIGS multishot	RIGS	RIGS	INTEQ *RIGS* multishot surveys	
BHI Seeker multishot	Seeker MS	SKR MS	All INTEQ *Seeker* (➔ 5.8) multishot surveys	
Ferranti FINDS multishot	FINDS	FINDS	All Ferranti *FINDS* (➔ 5.8) surveys	
Gyrodata - gyrocompassing m/s	GYD GC MS	GYD GC	Older Gyrodata gyro multishots, plus all battery/memory tool surveys (*RGS-BT*)	Replaces ex-BP “Gyrodata multishot into open hole” model.
Gyrodata - cont. casing m/s	GYD CT CMS	GYD CC	Gyrodata multishot surveys with continuous tool (*RGS-CT*) in casing. OD 13-3/8” or less.	
Gyrodata - cont. drillpipe m/s	GYD CT DMS	GYD CD	Gyrodata pump-down multishot surveys with continuous tool (*RGS-CT*) in drill-pipe.	
Gyrodata - large ID casing m/s	GYD LID MS	GYD LC	Gyrodata multishot surveys (gyrocompassing or continuous tool) in larger size casing strings (greater than 13-3/8” OD).	Includes an increased misalignment term
Gyrodata – bat/mem drop m/s	GYD BM MS	GYD BM	Gyrodata multishot using Battery/Memory tool in any configuration.	

Table B.3 Approved Survey Tool Error Models - North Seeking and Inertial Gyro Multishots (Part 1 of 2)

Approved Error Model	Short Name (Compass)	Short Name (DIMS)	Application	Remarks
Schlumberger GCT multishot	GCT MS	GCT	*GCT* surveys in casing or open hole.	*GCT* = "*Gyro Continuous Tool*" (➔ 5.8)
SDC Finder - multishot	Finder MS	FDR MS	*Finder* multishots in casing or drill pipe	Replaces ex-BP "Inrun" and "Outrun" models
SDC Keeper - casing m/s	KPR csg MS	KPR CM	*Keeper* multishot surveys in casing. OD 13-3/8" or less.	
SDC Keeper - drillpipe m/s	KPR d/p MS	KPR DP	*Keeper* pump-down multishot surveys in drill-pipe.	
SDC Keeper - large ID csg m/s	KPR LID MS	KPR LC	*Keeper* multishot surveys in larger size casing strings (greater than 13-3/8" OD).	Includes an increased misalignment term
Sperry-Sun G2 multishot	G2 gyro MS	G2 MS	*G2* (➔ 5.8) multishots in casing, drill pipe or open hole	Replaces ex-BP "Static" and "Dynamic" models

Table B.3 Approved Survey Tool Error Models - North Seeking and Inertial Gyro Multishots (Part 2 of 2)

Approved Error Model	Short Name (Compass)	Short Name (DIMS)	Application	Remarks
`Inclinometer (Totco/Teledrift)`	`INC`	`INC`	Inclination only surveys in near-vertical hole, including *TOTCO*, *Teledrift* and *Anderdrift.*	
`Inclinometer + known azi trend`	`INC+trend`	`INC+TR`	Inclination only surveys in near-vertical hole, where formation dip and experience enables direction of drift to be predicted.	Replaces ex-BP "Inclinometer (azimuth in known quadrant)" model

Table B.4 Approved Survey Tool Error Models - Inclination Only Surveys

Approved Error Model	Short Name (Compass)	Short Name (DIMS)	Application	Remarks
Camera-based mag single shot	CB mag SS	CBM SS	Traditional (mechanical) magnetic single shot (➔ 5.5)	Assumes tandem probes are run and that both are adequately magnetically spaced. Replaces ex-BP “PMSS”.
Conventional SRG single shots	SRG	SRG	Optically-referenced gyro single shots (➔ 5.6) Includes SDC *Keeper* when used in “siteline reference mode”.	Tool types include *SRG* and *MSRG* (scientific Drilling), *Sigma* (INTEQ) and *SRO* (Sperry-Sun).
Camera-based gyro single shots	CB gyro SS	CBG SS	Traditional surface referenced gyro tool run on wireline, including “level rotor” gyros and Sperry-Sun SU3.	Replaces ex-BP “PGSS” model.
Gyrodata - gyro single shots	GYD SS	GYD SS	Gyrodata gyro orientation surveys	
SDC Keeper - gyro single shots	KPR SS	KPR SS	*Keeper* gyro orientation surveys	Excludes siteline (ie. surface) referenced surveys
SDC Keeper – surface ref s/s	KPR SR SS	KPR SR	*Keeper* gyro orientation surveys, where azimuth alignment is achieved by optical referencing at surface.	
SDC Finder - gyro single shots	Finder SS	FDR SS	*Finder* gyro orientation surveys	
NS Gyro single shots	NS gyro SS	NSG SS	North seeking gyro orientation surveys taken with unspecified tool.	Note Gyrodata, SDC *Keeper* and SDC *Finder* have their own models, which should be used if the tool type is known to be one of these.

Table B.5 Approved Survey Tool Error Models - Other Single Shot Types

Approved Error Model	Short Name (Compass)	Short Name (DIMS)	Application	Remarks
`Camera-based gyro multishot`	`CB gyro MS`	`CBG MS`	Traditional optically referenced gyro surveys run on wireline, including “level rotor” gyros and Sperry-Sun *SU3* (➔ 5.8).	Replaces ex-BP “PGMS” model.
`Camera-based magnetic multishot`	`CB mag MS`	`CBM MS`	Traditional (mechanical) magnetic multishot (➔ 5.5)	Assumes adequate magnetic spacing. Replaces ex-BP “PMMS”.
`Dipmeter or other wireline log`	`Dipmeter`	`DIPMTR`	Wireline conveyed logging tools with directional survey capability (➔ 5.7).	Schlumberger *OBDT*, *BGT* are examples
`Sperry-Sun BOSS gyro multishot`	`BOSS gyro`	`BOSS`	Sperry-Sun *BOSS* multishot surveys (➔ 5.8).	

Table B.6 Approved Survey Tool Error Models - Other Multishot Types

Approved Error Model	Short Name (Compass)	Short Name (DIMS)	Application	Remarks
`Blind drilling`	`Blind`	`n/a`	Hole intervals where no surveys are taken	Model assumes well direction deviates from last known survey at a constant rate. Errors grow with square of distance drilled.
`Unknown survey`	`Unknown`	`n/a`	Any survey data of unknown or dubious type	Replaces ex-BP “unknown multishot” model.
`Zero Error model`	`Zero Error`	`n/a`	Used to set position uncertainty to zero down to a given depth (eg. side-track point).	

Table B.7 Approved Survey Tool Error Models - Special Models

Appendix C
Data and Work Sheets

Contents

Appendix C

Data and Work Sheets

Checklists and proformas to facilitate auditability and quality assurance.

This appendix contains examples of the type of form which should be used to control the directional planning, drilling and surveying operation. Operations that wish to may incorporate them directly into their system for technical integrity. Operations that have similar process checks already in place may continue to use them, but should check that they cover the same specific points.

All operations must be able to demonstrate an auditable trail from the well objectives, through planning and execution to data delivery and archival.

Completed examples illustrate how each sheet should be used.

Electronic versions of each form are available from the Directional and Survey Specialist, UTG Well Integrity Team or via the wellsONLINE page of the BP Amoco Intranet by following the 'Well Engineering' and 'Directional Drilling' links.

Surface Position Control Forms

These forms and memoranda are used by the BP Amoco Survey Network to ensure the correct definition of planned and actual well surface and target locations. Business Units

are strongly recommended to use this type of form for all their wells.

WELL LOCATION MEMORANDUM

➔ The function of the Well Location Memorandum is discussed in more detail in Section 6.3

This multipage form serves to correctly and unambiguously define the planned surface and sub-surface locations of all wells. The format of the form may differ between operating areas, but the content will be similar. The example shown is typical.

FINAL WELL POSITION MEMO (COMPLETED EXAMPLE)

Issued by a Company Surveyor to confirm the as-built well surface location and an estimate of its uncertainty. This memo defines the definitive surface location for the well.

FINAL WELL LOCATION DATA FORM (COMPLETED EXAMPLE)

➔ DGPS and other surface positioning systems are described in Section 3.1

Gives full details of the surface positioning systems (usually DGPS) used to determine the as-built well position, and how the definitive well co-ordinates were computed from the measurements made. There is a similar form designed for subsea well locations determined by acoustic positioning.

Directional Survey Control Forms

These data sheets and forms may be completed by the Drilling Engineer, Survey Manager or Well Planner. They serve to record the key steps in any directional survey process which follows the design-execute principle (➔ 1.3).

DIRECTIONAL DESIGN DATA SHEET

Records basic positional data provided by the BU to the directional company to initiate well planning. All updates to the data should be issued on new sheets. The directional company should reconfirm the data on the most recently issued sheet before printing drilling plots.

DIRECTIONAL DESIGN CHECK LIST

Confirms that the Well Planner has performed all the analyses necessary to confirm that the design meets its objectives, and has recorded the results. May be used as a contents page and sign-off sheet for the Directional Design File (➔ 6.4).

SURVEY PROGRAM DATA SHEET

Records details of the survey program. Should be included in the Directional Design File, the Well Survey File and the Well Program.

ANTI-COLLISION INSTRUCTION SHEET

Defines well shut-in requirements and other anti-collision instructions to the rig team. Also lists the key assumptions underlying the evaluation of Tolerable Collision Risk for any Minor risk wells. Should be included in the Directional Design File and the Well Program.

DISPENSATION FROM RECOMMENDED PRACTICE

Gives justification and approval for deviating from the procedures and standards detailed in this Handbook. This form is not suitable for recording deviations from Drilling and Well Operations Policy, for which there is a separate process.

NON-COMPLIANCE / NON-CONFORMANCE REPORT

Describes the circumstances and consequences of any failure of due process, and any actions arising. It should be used to record:

1. Any violation of the procedures and standards detailed in this Handbook for which dispensation had not been obtained (‘Non-compliance’).

2. Any failure to execute the directional plan or survey program in accordance with its design (‘Non-conformance’).

In the case of non-conformance, the actions should include a design review (➔ 6.5). A copy should be included in the Directional Design File or Well Survey File as appropriate.

Other Forms

TOLERABLE COLLISION RISK WORKSHEET

Uses a simple cost-benefit analysis to establish the maximum tolerable risk of collision with a Minor risk well (➔ 4.3, 4.4). Key assumptions underlying the analysis should be included in the anti-collision instructions to the rig.

DIRECTIONAL SURVEY HANDBOOK CHANGE REQUEST

Use this form for any corrections/suggestions you have on this Handbook. The forms will be kept and considered as part of the periodic Handbook review.

WELL LOCATION MEMORANDUM

LOCATION DESIGNATION

This WLM supersedes the following previous locations:

(NB: Any change in shotpoint location must have a new location designation)

Country: ______________ Prospect/Field: ______________
Region/State: ______________ Lease/PSC/Block: ______________

1. WELL LOCATION DEFINITION (To be completed by Buisiness Unit subsurface and/or reservoir team)

SURFACE LOCATION:

PRIMARY DEFINITION: 3D, 2D, HR Seismic Survey or OTHER* (* Circle appropriate definition)

Survey name: ______________ Survey mnemonic: ______________
Database type & name: ______________ 3D Inline bin, or 2D/HR line number: ______________
Acquisition contractor & year: ______________ 3D Xline bin, or 2D/HR shot number: ______________
Processing contractor & year: ______________ 3D bin size (Inline x Xline): or 2D/HR shotpoint interval: ______________

OTHER DEFINITION (eg: template & slot No.): ______________

SECONDARY DEFINITION: 3D, 2D or HR* Seismic Survey (* Circle appropriate definition)

Survey name: ______________ Survey mnemonic: ______________
Database type & name: ______________ 3D Inline bin, or 2D/HR line number: ______________
Acquisition contractor & year: ______________ 3D Xline bin, or 2D/HR shot number: ______________
Processing contractor & year: ______________ 3D bin size (Inline x Xline): or 2D/HR shotpoint interval: ______________

PRIMARY DRILLING TARGET LOCATION (for non-vertical wells):

PRIMARY DEFINITION: 3D, 2D or HR* Seismic Survey (* Circle appropriate definition)

Survey name: ______________ Survey mnemonic: ______________
Database type & name: ______________ 3D Inline bin, or 2D/HR line number: ______________
Acquisition contractor & year: ______________ 3D Xline bin, or 2D/HR shot number: ______________
Processing contractor & year: ______________ 3D bin size (Inline x Xline): or 2D/HR shotpoint interval: ______________

Section 1 completed by:	**Section 1 approved by:**
Signature: ______________	Signature: ______________
Date: ______________	Date: ______________
Name: ______________	Name: ______________
Position/Job Title: ______________	Position/Job Title: ______________

Well Location Memorandum - Page 2

LOCATION DESIGNATION

2. SUBSURFACE DATA (To be completed by Business Unit Subsurface Team)

Attach a separate map sheet to this WLM showing seismic lines and geological structure around target location

Describe below in words and diagramatically the surface location and it's constraints (give dimensions):

TOLERANCE Define Surface Location Tolerance(s)

Proposed Location

Surface Location Area Diagram

Illustrate shape and size of the zone within which a surface location would be acceptable and indicate constraints which limit rig anchoring or manoevring (eg: shallow gas, obstructions, pipelines).

For location(s) derived from workstation provide:

Coordinates of surface and primary target locations and two other bins remote from the primary target (one bin with same Inline and one with same Xline bin number as primary target)

Location	3D Survey Name	Bin Size	Inline	Xline	Eastings	Northings
Surface:						
Primary Target:						
Same Inline:						
Same Xline:						

For surface and target locations based on 2D or HR seismic provide:

Location	2D/HR Survey Name	Point*	Line No.	Shotpoint	Eastings	Northings
Surface:						
Primary Target:						

* Mapped point type (SP, CDP, etc)

Attach extract of relevant 2D and/or HR line from database listing shotpoint coordinates values for 2km either side of proposed location

Well Location Memorandum - Page 3

LOCATION DESIGNATION

3. WELL LOCATION COORDINATES (To be completed by UTG SURVEY GROUP)

LOCATION COORDINATES

SURFACE LOCATION (Vertical or Deviated well)		PRIMARY TARGET LOCATION (Deviated well)	
Latitude:		Latitude:	
Longitude:		Longitude:	
Eastings:		Eastings:	
Northings:		Northings:	
Surface Positioning Tolerance:		True azimuth from surface location:	degrees
Water depth:		Horizontal offset distance:	m ft
Ground Elevation:			

Geodetic Information:

Datum name:		Datum mnemonic:	
Ellipsoid name:		Ellipsoid mnemonic:	
Projection name:		Projection mnemonic:	Zone:

Data source of coordinates (eg: database name, report, etc):

Surface Location:	
Primary Target Location:	

Seismic survey positioning systems and horizontal accuracy estimates:

	Surface Location		Primary Target Location	
	Positioning System	Accuracy	Positioning System	Accuracy
3D Seismic:				
2D Seismic:				
HR Seismic:				

Other positioning information:

Section 3 completed by:	Section 3 approved by:
Signature:	Signature:
Date:	Date:
Name:	Name:
Position/Job Title:	Position/Job Title:

Circulation:

D.S. / S.D.E. / D.E.	Site Investigation Specialist
Subsurface Team Leader	Data Administrator (load to database)
Asset Geoscientists	Head of Survey

FINAL WELL POSITION MEMO - EXAMPLE

SENIOR DRILLING ENGINEER

BP REPRESENTATIVE ONBOARD RIG

HSE, ABERDEEN

OG Data Admin Group, DTI, LONDON

Final Position of Guidebase for SCHIEHALLION WEST Well 204/20-W03(Slot WW06)

The final seabed position for the Schiehallion West Well W03, installed by the Henry Goodrich, as determined by LBL EHF Acoustics is as follows:

Latitude	: 60° 20' 00.42"N	(ED50, International 1924 Ellipsoid)
Longitude	: 04° 05' 55.39"W	
Easting	: 439 332.6 mE	(UTM Zone 30 CM 3° W)
Northing	: 6 689 210.3 mN	

This position is 0.76 metres on a bearing of 40.87° True from the intended location 204/20-WW1 (Slot WW06). This can be taken as the definitive position of the well. The accuracy for this position is 1 metre in absolute terms but locally with respect to other subsea features the accuracy is 0.25 metres.

Guidebase Orientation/Attitude

46.5° Grid 45.5° True
The accuracy of the Guidebase orientation is +/- 3 Degrees
The intended orientation of the guidebase was 53.5° Grid.

Height of Top of 36" Casing above mean seabed

1.6 metres above estimated seabed level on the DMAC approach
The accuracy of the 36" casing height is +/- 0.2 metres
The intended casing height was 1.5 metres.

Would you please ensure that these are the only surface co-ordinates included on correspondence, including Well Completion Reports.

Head of Survey & Seismic Operations
Ext. 2587

Date : 30th March 1998

c.c.	Rig Move File	T.Geddes SSO
	P.Sen, MB4337	B.Johanson, MB4315
	M.Murawiecki, MB4337	M.Johnson, MB4315
	S.Sibbett CCL	M.Munt, SSO
	H.Wylie, MB4337 M.Morrison	

Country: UK	Area: UKCS
Prospect/Field: Bruce	

FINAL WELL LOCATION DATA

Submit to BP Amoco Survey for checking/approval

Date Completed:

Well Number:	9/8a-18
Location designation:	9/8a-U

Accepted Surface Position

(Geogs: 2 dec places, Grid: 1 dp (m) 0 dp (ft))

Lat:	59°44′ 02.20″ N	Long:	01°34′ 22.70″ E
Geodetic Datum	ED 50	Projection and zone:	UTM Zone 31
Easting:	419 765.6	Northing:	6 622 799.0

Radius of error:	+/- 5 m
System/method for accepted position	Skyfix DGPS
Secondary positioning system:	Deltafix DGPS
Rig positioning contractor:	RACAL
Job number:	
Site survey date:	
Contractor:	
Report number:	
Rig name:	Ben Reoch
Type of rig:	
Vertical datum:	Mean Sea Level
Water depth – B.M.S.L. or stated Vert Datum	120.2 m
Water depth – B.L.A.T.	119.4 m
RTE – A.M.S.L	36.6 m

Primary Positioning System

(Geogs: 3 dec places, Grid: 2 dec places)

Names of Reference Station(s) used for Primary Position

Antenna Position: WGS84 Datum

Lat:	59°44′ 01.371″ N
Long:	01°34′ 13.971″ E
Sph. Ht.	

Offset: Antenna to rotary

(Relative range/bearing)

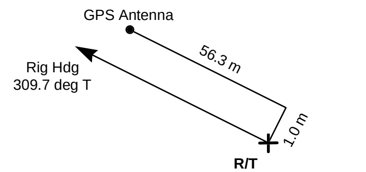
56.3 m @ 130.7° True

Coords of rotary: Local Datum

Lat:	59°44′ 02.204″ N
Long:	01°34′ 22.697″ E
Ellip. Ht.	
Easting:	419 765.63
Northing:	6 622 799.04

S.D. X: Y: Z:

Diagram



Secondary Positioning System

(Geogs: 3 dec places, Grid: 2 dec places)

Ref.Stn.1: Name/Country:		
Lat.	Long.	
Easting	Northing	
Dist to Ref.Stn.		km
Ref.Stn.2: Name/Country:		
Lat.	Long.	
Easting	Northing	
Dist to Ref.Stn.		km
Ref.Stn.3: Name/Country:		
Lat.	Long.	
Easting	Northing	
Dist to Ref.Stn.		km

Antenna Coords: Network Solution WGS84 Datum

Lat.	59°44′ 01.517″ N	
Long	01°34′ 15.452″ E	Sph.Ht.
S.D.	X: Y:	Z:

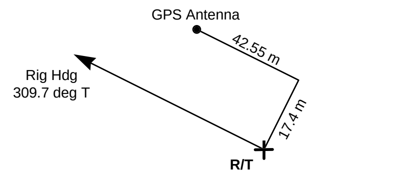
Offset: Antenna to rotary *(Rel. range/bearing)*

49.5 m @ 151.9° True

Coords of rotary: Local Datum

Lat.	59°44′ 02.219″ N	
Long	01°34′ 22.840″ E	
Easting:	419 767.72	S.D.
Northing	6 622 799.57	S.D.

Diagram



Contractors report no.

Geodetic Parameters

Associated Ellipsoid	International 1924
Semi-major axis	6 378 388 m
Semi-minor axis	
Reciprocal flattening	1/297

Datum Shift

From WGS84 to Local Datum

dX: 89.5 m	dY: 93.8 m	dZ: +123.1 m
rX: 0	rY: 0	rZ: +0.156″
Scale Factor:	-1.2 ppm	

Useful Information / Notes

This form compiled by Hugh Williamson as an illustration for the Directional Survey Handbook. Not all co-ordinates shown are correct.

Completed by: *(block caps)* A.SMITH

Checked by: *(block caps)* B.JONES

WELL PLAN DATA SHEET

* delete as appropriate

Rig / Platform / Drill Site*	Well
Sheet completed by	Date

SURFACE LOCATION planned / actual*	Datum/Ellipsoid Projection

Structure reference Description		
Lat.	N / S*	Easting
Long.	E / W*	Northing

Well reference point Description		
Lat.	N / S*	Easting
Long.	E / W*	Northing
Offset from structure ref.	N / S*	E / W*

Elevation (land rig)	**Elevation (offshore)**
Drill datum RT / KB*	Drill datum RT / KB*
Drill datum to well ref. pt.	Drill datum to MSL
Well ref. pt. to MSL	Drill datum to well ref. pt.

TARGET #1	**TARGET #2**	**TARGET #3**
Name	Name	Name
Easting	Easting	Easting
Northing	Northing	Northing
Depth TVDss	Depth TVDss	Depth TVDss
Tolerance	Tolerance	Tolerance

Survey reference True / Grid*

Grid convergence (T to G) E / W*
Magnetic declination (T to M) E / W*
Magnetic model Date
Correction (magnetic to survey ref.)
Correction (true to survey ref.)

North arrows (diag.)

Curved conductors

Drill datum to well reference point

MD	TVD	North	East
		N / S*	E / W*

Incl. at w.r.p. Azim at w.r.p.

WELL PLAN DATA SHEET	* delete as appropriate
Rig / Platform / Drill Site* VICTORY B	Well VB-19
Sheet completed by Joseph P. Bloggs	Date 17 Oct 05

SURFACE LOCATION planned / ~~actual~~*	Datum/Ellipsoid	Projection
	NAD 27 / Clarke 1866	BLM 15N (ft)

Structure reference	Description	Slot 01		
Lat.	28°31'56.78" N / ~~S~~*		Easting	X = 3212781.24
Long.	88°06'17.01" ~~E~~ / W*		Northing	Y = 10386482.94

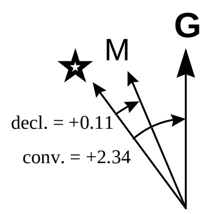
Well reference point	Description	Slot 08 (Sea bed)		
Lat.	28°31'56.52" N / ~~S~~*		Easting	X = 3212785.89
Long.	88°06'16.97" ~~E~~ / W*		Northing	Y = 10386456.79
Offset from structure ref.	26.15' ~~N~~ / S*	4.65' E / ~~W~~*		

Elevation (land rig)		**Elevation (offshore)**	
Drill datum RT / KB*		Drill datum RT / ~~KB~~*	
Drill datum to well ref. pt.		Drill datum to MSL	124.0'
Well ref. pt. to MSL		Drill datum to well ref. pt.	1786.0'

TARGET #1	**TARGET #2**	**TARGET #3**
Name PC	Name PD	Name
Easting X = 3218800	Easting X = 3219700	Easting
Northing Y = 10393420	Northing Y = 10393820	Northing
Depth TVDss 10665'	Depth TVDss 11020'	Depth TVDss
Tolerance 150' North 100' East 100' West 200' South	Tolerance 3219650 E 10394920 N 3219800 E 10393870 N 3219800 E 10393720 N 3219650 E 10393720 N	Tolerance

Survey reference ~~True~~ / Grid*		
Grid convergence	(T to G)	2.34° E / ~~W~~*
Magnetic declination	(T to M)	0.11° E / ~~W~~*
Magnetic model BGGM 05		Date 1 Nov 05
Correction (magnetic to survey ref.)		-2.23°
Correction (true to survey ref.)		-2.34°

North arrows (diag.)



Curved conductors

Drill datum to well reference point

MD	TVD	North	East
1787.2'	1786.0'	6.24' ~~N~~ / S*	1.10' E / ~~W~~*
Incl. at w.r.p. 4.17°		Azim at w.r.p. 168.78°	

DIRECTIONAL DESIGN CHECK LIST		
Rig / Platform / Drill Site	Well	
		Date
Sheet completed by		
Checked by		
	✓/×	Comment
Well Objectives		
Document from BU sub-surface team		
Updates to well objectives		
Well Location Memorandum		
Planning File		
Well Plan Data Sheet		
Survey Program Data Sheet		
Proposed well trajectory		
BU sub-surface approval of trajectory		
Target analysis (1 per target)		
Offset well data (surveys, completion diags. etc.)		
Initial clearance scan (global scan)		
Tolerable Collision Risk Worksheet(s)		
Minimum separation calculations		
Anti-Collision Instruction Sheet		
Magnetic interference prediction		
Relief well contingency calculation		
Dispensations from Recommended Practice		
Wellsite Drawings		
Plan view drawings		
Vertical section drawings		
Structure (spider) plots		
Travelling cylinder - global clearance scan Travelling cylinder - working drawing(s) Travelling cylinder - wellsite plots		

DIRECTIONAL DESIGN CHECK LIST		
Rig / Platform / Drill Site: **VICTORY B**	Well: **VB-19**	
		Date
Sheet completed by: **Joseph P. Bloggs**		**23 Oct 05**
Checked by: **A. Smith**		**25 Oct 05**
	✓/×	Comment
Well Objectives		
Document from BU sub-surface team	✓	**Well Data Pack, H.Nelson, 7/30/05**
Updates to well objectives	✓	**Target 2 change - H.Nelson e-mail 10/17/05**
Well Location Memorandum	✓	**D.Williams, 9/15/05**
Planning File		
Well Plan Data Sheet	✓	
Survey Program Data Sheet	✓	
Proposed well trajectory	✓	**version 2.6**
BU sub-surface approval of trajectory	✓	**H.Nelson e-mail 10/20/05**
Target analysis (1 per target)	✓	
Offset well data (surveys, completion diags. etc.)	✓	**VB-2 completion diagram attached**
Initial clearance scan (global scan)	✓	
Tolerable Collision Risk Worksheet(s)	✓	**VB-2**
Minimum separation calculations	✓	**See SATURN printout**
Anti-Collision Instruction Sheet	✓	
Magnetic interference prediction	✓	**See SATURN printout**
Relief well contingency calculation	✓	
Recommended Practice Dispensation Form(s)	✓	**Target PD confidence level**
Wellsite Drawings		
Plan view drawings	✓	
Vertical section drawings	✓	**x 2**
Structure (spider) plots	✓	**Not required**
Travelling cylinder - global clearance scan	✓	
Travelling cylinder - working drawing(s)	✓	
Travelling cylinder - wellsite plots	✓	**x 2**

SURVEY PROGRAM DATA SHEET

Rig / Platform / Drill Site	Well	Program version	Sheet completed by	Date

Survey Tool / Error Model	Hole Size	Casing Size	Depth interval from	Depth interval to	Comments / Contingency

SURVEY PROGRAM DATA SHEET

Rig / Platform / Drill Site	Well	Program version	Sheet completed by	Date
VICTORY B	VB-19	4	Andy Smith	10/23/05

Survey Tool / Error Model	Hole Size	Casing Size	Depth interval from	Depth interval to	Comments / Contingency
SDC Keeper - Orientation Shots	24”		1787’	2125’	
SDC Keeper - Orientation Shots	17-1/2”		2125’	2500’	Continue until free of magnetic interference
MWD - Standard	17-1/2”		2500’	3145’	Tandem probe electronic multishot at section TD if drilled in single bit run
MWD + BHA Sag Correction	12-1/4”		3145’	12110’	
Gyrodata - Casing Multishot		9-5/8”	1787’	12110’	
MWD + BHA Sag Correction	8-1/2”		12110’	14420’	Tandem probe electronic multishot at section TD if drilled in single bit run

ANTI-COLLISION INSTRUCTION SHEET

Rig / Platform / Drill Site	Well

	Date
Sheet completed by	
BU authorisation	

The instructions given in this sheet are based on: 999

Well plan no.	Date	Survey program no.	Date

and are not otherwise valid.

Wells to be Shut In

Well name	Slot	Minimum Shut-in Interval MD from	MD to	Comment

Minor Risk Wells

Well name	TCR*	Key Assumptions

*Tolerable Collision Risk

Travelling Cylinder Plots

Plot no.	Depth from	Depth to	Date	Comment

Contingency Plans / Special Instructions

ANTI-COLLISION INSTRUCTION SHEET

Rig / Platform / Drill Site	Well
VICTORY B	VB-19

	Date
Sheet completed by Joseph P. Bloggs	25 Oct 05
BU authorisation Kim Colbert	11/03/05

The instructions given in this sheet are based on:	
Well plan version no. 2.4	Date 19 Oct 05
Survey program version no. 4	Date 23 Oct 05
	and are not otherwise valid.

Well Shut-ins

Well name	Slot no.	Minimum Shut-in Interval MD from	MD to	Comment
VB-16	07	1787'	2125'	DD - check exact status if 20" casing is set shallow
VB-02A	13	1787'	2300'	

Minor Risk Wells

Well name	TCR*	Key Assumptions
VB-2	1 in 20	Drilling mud weight @ 12300 ft MD at least 12 ppg

*Tolerable Collision Risk

Travelling Cylinder Plots

Plot no.	Depth from	Depth to	Date	Comment
1	1787'	3145'	24 Oct 05	
2	3145'	TD	24 Oct 05	

Contingency Plans / Special Instructions

Well has been planned to allow well VB-22 (slot 12) to remain flowing. Decision for contingent shut-in to be taken by BU Drilling team on advice of Directional Driller while setting 20" casing.

Close approach (150') to P&A well VB-2 at 12300' MD. No special precautions or avoidance measures necessary. Directional Driller to make rig team aware of small probability of collision.

DISPENSATION FROM RECOMMENDED PRACTICE	
To be used for recording planned violations of standard directional and survey procedures and recommended practices	
Rig / Platform / Drill Site	Well
	Date
Sheet prepared by	
Recommended Practice Document	
Procedure / Standard to be violated	
Details of Dispensation Requested	
Justification	
Attachments	
Technical Assessment / Recommendation	Signature / Date / Comment
BU Authorisation	

DISPENSATION FROM RECOMMENDED PRACTICE	
To be used for recording planned violations of standard directional and survey procedures and recommended practices	
Rig / Platform / Drill Site **VICTORY B**	Well **VB-19**
Sheet prepared by **Andy Smith**	Date **10/22/05**
Recommended Practice Document **Victory Development Directional Basis of Design**	
Procedure / Standard to be violated **Target analysis confidence level (95%)**	
Details of Dispensation Requested **Driller's target for target PD to be calculated at 80% confidence.**	
Justification **Practical minimum size for driller's target taken as 50' across. No cost-effective option for substantially reducing position uncertainty or enlarging geological target. Reduced confidence level agreed with Helen Nelson.**	
Attachments **1) Target analysis print-outs at 95%, 85% and 80% confidence.** **2) H. Nelson e-mail, 21 Oct 05**	
Technical Assessment / Recommendation **OK. Consider in-field referencing for future wells**	Signature / Date / Comment **J. Taylor, UTG-WIT, 26 Oct 05**
BU Authorisation **Approved.**	**B. Jones, Victory Wells TL, 28 Oct 05**

NON-COMPLIANCE / NON-CONFORMANCE REPORT		
To be used for reporting unplanned violations of standard directional and survey procedures or unplanned deviations from directional plan or survey program		
Rig / Platform / Drill Site	Well	
		Date
Sheet prepared by		
Procedure / Standard / Plan / Program document		
Procedure / Standard / Plan / Program violated		
What happened		
Most serious likely consequence		
Contributory causes		
Action	Responsible	Date

NON-COMPLIANCE / NON-CONFORMANCE REPORT

To be used for reporting unplanned violations of standard directional and survey procedures
or unplanned deviations from directional plan or survey program

Rig / Platform / Drill Site	Well
VICTORY B	**VB-19**

Sheet prepared by	Date
Andy Smith	**01/06/06**

Procedure / Standard / Plan / Program document

1. Drilling Program section 6 - Surveying Program

Procedure / Standard / Plan / Program violated

12-1/4" section - MWD+BHA Sag Correction Surveys

What happened

MWD surveys in 12-1/4" section were not corrected for BHA sag in real-time. Directional Driller (G. Brown) thought SATURN software applied correction automatically. MWD engineer (S. Green) had not seen survey program.

Most serious likely consequence

In this well, error could have required extra directional work in 8-1/2" section. In other Victory wells, where 9-5/8" gyro is not run, target could have been missed. Negligible increase in anti-collision risk.

Contributory causes

Directional Driller was unfamiliar with SATURN software, and used his own ACME software for survey calculation.

MWD company had not been told of requirement for sag correction

Action	Responsible	Date
Need for sag correction to be noted on Survey Program Data Sheet where appropriate	**A. Smith**	**Future wells**
Directional Company to amend quality procedures to: **1. Ensure all DD's trained on SATURN data entry** **2. Send copy of Survey Program Data Sheet to all survey company Operations Supervisors prior to spud.**	**A. Smith**	**02/01/06**

Tolerable Collision Risk Worksheet

Use this sheet to justify classifying a well as Minor risk and to establish the Tolerable Collision Risk for use in risk-based well separation rule.
Ref. BPA-D-004 (Dir. Svy. H'book) Sections 4.2, 4.3

Prepared by:

Authorised by:

Scenario Name:

Description: *(Be specific. Include all factors which affect either the cost of collision or the cost of reducing the risk)*

Are the consequences of collision predictable ?

no → **STOP** Use Conventional rule - Major risk

yes → **Do the consequences of collision include a risk to personnel or the environment ?**

yes → **STOP**

no → **List all the consequences of collision and the necessary remedial action**

Key Assumptions *(Elements of the drilling program which are critical to the above analysis)*

Estimate the total cost of collision $C =$

Is there a practical way to substantially reduce either the probability of collision or the severity of the consequences ?

yes → **How could the probability of collision or the severity of the consequences be reduced ? How might this impact the drilling operation ?**

Estimate the total cost of substantially reducing the risk $V =$

Given the uncertainty in the above estimates, by how many times must the savings made from not reducing the risk outweigh the risk itself ? (guideline = 20)

$M =$

$F = \frac{1}{M} =$

no → **Estimate the value of the planned well to the BU**

$V =$

Accepting a finite risk of collision will reduce the value of the planned well. What reduction, as a fraction of the total value, are you prepared to tolerate ? (guideline = 0.05)

$F =$

Tolerable Collision Risk $= \frac{VF}{C} =$

$\frac{VF}{C}$ **> 1 : close approach tolerances need not be set**

$\frac{VF}{C}$ **< 1 : Tolerable Collision Risk = 1 in** $\frac{C}{VF}$ **= 1 in**

H.Williamson, UTG Well Integrity

Tolerable Collision Risk Worksheet

Use this sheet to justify classifying a well as Minor risk and to establish the Tolerable Collision Risk for use in risk-based well separation rule.
Ref. BPA-D-004 (Dir. Svy. H'book) Sections 4.2, 4.3

Prepared by: Stuart Telfer (Directional Engineer)

Authorised by: Richard Harland (Ops Superintendant)

Scenario Name: **Marnock A01Y Parallel S/T in Reservoir**

Description: *(Be specific. Include all factors which affect either the cost of collision or the cost of reducing the risk)*

Sidetracking an existing well (A01Z) by paralleling it through the reservoir section. Original well is sidetracked below the 13 3/8" casing drilling 12 1/4" and 8 1/2" hole sections. The original well, under conventional rules is classed as MINOR risk as it is closed in and abandoned. Interference occurs in 8 1/2" hole from 4060m to 4590m.

Are the consequences of collision predictable ? — no → **STOP** Use Conventional rule - Major risk; yes →

Do the consequences of collision include a risk to personnel or the environment ? — yes → STOP; no →

List all the consequences of collision and the necessary remedial action

1. Estimated treatment due to contamination from original wellbore and potential mud loss — £ 50k
   Mud loss is not expected, merely contamination through barite sag in the original hole requiring treatment to the sidetrack hole system.
2. Potential well control due to reservoir fluid on the highside of the original wellbore — £ 200k
   (est. 2 days rig time @ £100k/day)
3. Plugback and sidetrack well (est. 6 days rig time @ £100k/day) — £ 600k

Key Assumptions *(Elements of the drilling program which are critical to the above analysis)*

Estimate the total cost of collision $C =$ **850k**

Is there a practical way to substantially reduce either the probability of collision or the severity of the consequences ? — no → **Estimate the value of the planned well to the BU** $V =$; yes →

How could the probability of collision or the severity of the consequences be reduced ? How might this impact the drilling operation ?

Moving South edges of the drillers target North by 10m at entry and 63m at TD would result in:

1. Increased directional control to achieve smaller targets, cost in extra rig time = **8 days**
2. Increased risk of sticking by 25% through greater sliding requirement, potential impact of becoming stuck, 12 days rig time.

0.25 x 12 days = **3 days**

Total = 11 extra days @ £100k/day

Estimate the total cost of substantially reducing the risk $V =$ **£ 1.10 m**

Given the uncertainty in the above estimates, by how many times must the savings made from not reducing the risk outweigh the risk itself ? (guideline = 20)

$M =$ **20**

$F = \dfrac{1}{M} =$ **0.05**

Accepting a finite risk of collision will reduce the value of the planned well. What reduction, as a fraction of the total value, are you prepared to tolerate ? (guideline = 0.05)

$F =$

<u>**Tolerable Collision Risk**</u> $= \dfrac{VF}{C} =$ **0.065**

$\dfrac{VF}{C}$ **> 1 : close approach tolerances need not be set**

$\dfrac{VF}{C}$ **< 1 :** <u>**Tolerable Collision Risk**</u> **= 1 in** $\dfrac{C}{VF}$ **= 1 in 15**

H.Williamson, SPR Well Design

Tolerable Collision Risk Worksheet

Use this sheet to justify classifying a well as Minor risk and to establish the Tolerable Collision Risk for use in risk-based well separation rule.
Ref. BPA-D-004 (Dir. Svy. H'book) Sections 4.2, 4.3

Prepared by: Larry Wolfson 12/6/96

Authorised by: Adrian Clark 15/6/96

Scenario Name: **Niakuk Segment 3/5 Development Wells**

Description: *(Be specific. Include all factors which affect either the cost of collision or the cost of reducing the risk)*

New development wells drilled to segment 3/5 locations encountering interference with adjacent wells. Shallow nudges and varying KOPs used to move the interference depth below the surface casing.

Are the consequences of collision predictable ? no → **STOP** Use Conventional rule - Major risk

yes → **Do the consequences of collision include a risk to personnel or the environment ?** yes → STOP

no →

List all the consequences of collision and the necessary remedial action

- Collision with a producer/injector results in a side-track of that well: \$2-\$2.5 million (based on P2-50B)
- Plug back and side-track the drilling well: \$200k - \$500k
- The cost of delayed production/injection from both wells is estimated at \$60 per bopd. NK-10 is a significant injector that supports 12,000 bopd and the average production from the producers is 3,000 bopd. The cost of a collision includes delayed production for both wells: - Injector: \$900k - Producer: \$360k
- Estimated total cost (range): \$2.56 - \$3.90 million.

Key Assumptions *(Elements of the drilling program which are critical to the above analysis)*

Surface casing set above start of zone of interference (6,600 ft MD)

Estimate the total cost of collision $C =$ **\$3.9 million**

Is there a practical way to substantially reduce either the probability of collision or the severity of the consequences ?

yes →

How could the probability of collision or the severity of the consequences be reduced ? How might this impact the drilling operation ?

Estimate the total cost of substantially reducing the risk $V =$

Given the uncertainty in the above estimates, by how many times must the savings made from not reducing the risk outweigh the risk itself ? (guideline = 20)

$M =$

$F = \frac{1}{M} =$

no →

Estimate the value of the planned well to the BU

$V =$ **\$8.0 million**

Accepting a finite risk of collision will reduce the value of the planned well. What reduction, as a fraction of the total value, are you prepared to tolerate ? (guideline = 0.05)

$F =$ **0.05**

Tolerable Collision Risk $= \frac{VF}{C} =$ **0.103**

$\frac{VF}{C}$ **> 1 : close approach tolerances need not be set**

$\frac{VF}{C}$ **< 1 : Tolerable Collision Risk = 1 in** $\frac{C}{VF}$ **= 1 in 10**

H.Williamson, SPR Well Design

Tolerable Collision Risk Worksheet

Use this sheet to justify classifying a well as Minor risk and to establish the Tolerable Collision Risk for use in risk-based well separation rule.
Ref. BPA-D-004 (Dir. Svy. H'book) Sections 4.2, 4.3

Prepared by: James O'Connor

Authorised by: Liam Cousins (Ops Superintendant)

Scenario Name: **Mungo 22/20-A09(169)[W12]**

Description: *(Be specific. Include all factors which affect either the cost of collision or the cost of reducing the risk)*

Interference with previous exploration and development wells when achieving W12 target. Well plan must pass between the two wells to achieve W12 target. Both wells are suspended. The development well is awaiting abandonment. The section of greatest collision risk with the development well has high percentage casing wear and is of no future use to the asset.

Are the consequences of collision predictable ? no → **STOP** Use Conventional rule - Major risk; yes →

Do the consequences of collision include a risk to personnel or the environment ? yes → **STOP**; no →

List all the consequences of collision and the necessary remedial action

Collision with either well would provide a conduit for reservoir pressure to into the 12 1/4" section of the planned well. However as the reservoir pressure is c.1.3sg and drilling fluid is 1.65sg the risk of a well control incident is no greater than when Top Reservoir Target is reached in 12 1/4" section.
Estimated costs:
1. Plugback and sidetrack well (estimate 4 days rig time @ £140k/day) £ 560k
2. Bit damage (estimate £50k) £ 50k

Key Assumptions *(Elements of the drilling program which are critical to the above analysis)*

Programmed FIT achieved at 13 3/8" casing shoe (the drilling programme calls for revision of risks if the FIT is not achieved).

Estimate the total cost of collision $C =$ **610k**

Is there a practical way to substantially reduce either the probability of collision or the severity of the consequences ?

yes →

How could the probability of collision or the severity of the consequences be reduced ? How might this impact the drilling operation ?

Collision risk would be reduced if the wellpath accessed the area via a much more tortuous path.

•250mMD extra -> £150k

•increased risk of stuck pipe -> £150k

•increased risk of not setting casing -> £300k

Estimate the total cost of substantially reducing the risk $V =$ **£600k**

Given the uncertainty in the above estimates, by how many times must the savings made from not reducing the risk outweigh the risk itself ? (guideline = 20)

$M =$ **20**

$F = \frac{1}{M} =$ **0.05**

no →

Estimate value of the planned well to the BU

$V =$

Accepting a finite risk of collision will reduce the value of the planned well. What reduction, as a fraction of the total value, are you prepared to tolerate ? (guideline = 0.05)

$F =$

Tolerable Collision Risk $= \frac{VF}{C} =$ **0.049**

$\frac{VF}{C} > 1$: **close approach tolerances need not be set**

$\frac{VF}{C} < 1$: **Tolerable Collision Risk** $= 1$ **in** $\frac{C}{VF} =$ **1 in 20**

H.Williamson, SPR Well Design

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DIRECTIONAL SURVEY HANDBOOK (BPA-D-004) - CHANGE REQUEST Forward to the Directional & Survey Specialist, UTG Well Integrity Team	
Request made by:	Date:
Business Unit / Organisation:	
Job Title:	
Tel:	E-mail:
Section Title:	Page(s) affected:
Details of Change	
UTG / ODL Action	